ADEQ
ARKANSAS
Department of Environmental Quality

November 5, 2008

Kris Gaus, Senior Environmental Specialist
American Electric Power Service Corp. - Turk Power Plant
PO Box 660164
Dallas, TX 75266-0164

Dear Mr. Gaus:

The enclosed Permit No. 2123-AOP-R0 is issued pursuant to the Arkansas Operating Permit Program, Regulation # 26.

After considering the facts and requirements of A.C.A. §8-4-101 et seq., and implementing regulations, I have determined that Permit No. 2123-AOP-R0 for the construction, operation and maintenance of an air pollution control system for American Electric Power Service Corp. - Turk Power Plant to be issued and effective on the date specified in the permit, unless a Commission review has been properly requested under §2.1.14 of Regulation No. 8, Arkansas Department of Pollution Control & Ecology Commission's Administrative Procedures, within thirty (30) days after service of this decision.

All persons submitting written comments during this thirty (30) day period, and all other persons entitled to do so, may request an adjudicatory hearing and Commission review on whether the decision of the Director should be reversed or modified. Such a request shall be in the form and manner required by §2.1.14 of Regulation No. 8.

Sincerely,

Mike Bates

Mike Bates
Chief, Air Division

incomplete, or, in some instances, was only made available late in the public comment period.

Response

ADEQ disagrees that commenters did not have the opportunity to conduct a meaningful review of modeling data.

When the Director of ADEQ made a draft permitting decision to issue SWEPCO an air permit, ADEQ published a notice of the draft permitting decision in a newspaper in Hempstead County and a statewide newspaper as required by Arkansas Pollution Control and Ecology (APC&EC) Regulation 26.

The publication contained the name, address, and telephone number of a person from whom interested parties could obtain additional information, including copies of the permit draft, the application, and all relevant supporting materials available to the Department. Notice of the draft permitting decision was published on June 12, 2007.

The initial request for files by the commenter was made on June 21, 2007. A link to download files was provided on June 29, 2007. This included all Class I information except meteorological files for which, because of the amount of data, the commenter was instructed to send external storage media to ADEQ so that ADEQ could copy the files. Such drives were sent on July 16 and 17, 2007 and returned to the commenter on the July 18, 2007 with the transferred data. A downlink to Class II files was provided on July 20, 2007. The closing date for submitting public comments was extended twice in this case, to insure that all commenters had access to materials relevant to the permit. Initially, the comment deadline was July 26, 2007, but it was extended to August 6, 2007.

The application material contained all the modeling protocols, data or data sources and results. Electronic files were conveyed to interested parties as soon as possible upon request.

A copy of the application material was sent to the Hempstead County library; however, it was not made available to the public. Sierra Club commenters brought this to the attention of ADEQ. A new copy of all the application material was immediately sent to the library when ADEQ became aware of the situation. ADEQ also extended the close of comment period to provide time for review of this material.

Modeling files

The commenter made no specific mention of any issue in the air quality analysis (modeling) analysis or emission estimation methodologies contained in the permit application. The comment is only related to the availability of electronic files used

by the applicant in dispersion modeling and emission calculations. Electronic files were provided for Class II modeling. In addition, the application material provided details of modeling parameters and other inputs used in the analysis. This includes emission rates used, receptor grids, meteorology, building dimensions, etc.

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Lack of spreadsheets, “encrypted” data

The commenters make reference to the failure to provide spreadsheets and source codes used by the applicant in calculating impacts or emissions. The claim is that without these it is impossible to review the many calculations and data. The applicant says this is important because predicted Class II impacts are 50% of the increment.

The ADEQ does not believe these items are necessary for review of the application for the reasons outlined below.

Modeling programs routinely organize output data to list the highest values. There is no need to review huge amounts of data. Once the modeling inputs are established and the program is run, the desired output is readily available.

No errors in the Class II modeling have been identified. It is irrelevant that the predicted impacts are 50% of the increment. The increment analysis show the facility’s predicted emissions to be within the allowable limits.

This information is in no way “encrypted” by being provided in pdf or other formats that do not contain the spreadsheets used. It is in fact, in a more readily understandable format than a spreadsheet. The application clearly lays out the methodology for each calculation and the parameters used. The resources needed to review emission calculations for errors are in fact trivial even without the electronic spreadsheets. The math is self evident and the number of identical calculations that benefit from a spreadsheet is minimal, certainly not the “many thousands of times” claimed.

The contention that a simple spreadsheet calculation can be construed in the same light as providing the source code for complex dispersion modeling is not accurate. The emission calculations in the application are easily reproduced in an independently produced spreadsheet or even with a simple calculator.

One file(s) the commenter references as missing, (aep-s032. *) is clearly in the information on record with ADEQ and would be part of any request for records.

2. The draft permit is incomplete.

   Several commenters made reference to an ADEQ "admission" of continued review specifically regarding modeling issues raised by U.S. EPA and the federal land manager. One commenter specifically states:

   It is also apparent that ADEQ's technical review and analysis is ongoing and was not complete at the time of draft permit issuance. The only appropriate remedy for these failures is for ADEQ to obtain all necessary data, complete its technical review, make all information relevant to the draft permitting decision available to the public, and then re-notice the 30-day public comment period.

Response

The ADEQ had completed its evaluation when the draft permit was issued. ADEQ is unaware of any specific review that was not completed before issuance of the draft. The draft permit is the proposed decision of ADEQ on the application. Arkansas law does not require ADEQ to provide notice and a comment period on everything that it reviews after it issues a draft permitting decision. The relevant Arkansas statutes and regulations mandate only that ADEQ provide notice and at least thirty days to comment on the draft permitting decision. This is a permitting process where the public comments help ADEQ to make a final decision. If ADEQ could not change the conditions of a permit after receiving comments, it would be placed in the position of either being unable to learn from the comments or being forced to commence new comment periods ad infinitum.

It is permissible for ADEQ to consider subsequent comments and issues raised by the EPA, the federal land manager or others during the draft period.

3. Global Warming

   Many commenters stated that ADEQ must consider global warming impacts that will result from the Turk plant. The plant will emit large amounts of CO_2 thus contributing to global climate changes.

   In addition one commenter questions "the applicants statement at the July 12, 2007, Public Hearing, that this plant "is being designed to account for" pending carbon dioxide regulations."

Response

SWEPCO has indicated that the design of the plant includes the designation of approximately 20 acres in the plot plan for future CO_2 capture equipment. They

also state that a preliminary study of the site geology indicates it is a candidate to support sequestration.

The commenter cites assessments from the International Panel on Climate Change, Climate Change 2007: The Physical Science Basis, Summary for Policy Makers, for the proposition that carbon dioxide emissions may be altering the earth's climate. The commenter opposes the building of the Turk plant because it will add carbon dioxide emissions to the atmosphere. ADEQ acknowledges these comments, but ADEQ lacks authority to regulate carbon dioxide.

ADEQ does not currently regulate all greenhouse gases. Specifically, carbon dioxide is not regulated under state or federal law. Neither the Clean Air Act (CAA) and corresponding Environmental Protection Agency (EPA) regulations, nor the Arkansas Water and Air Pollution Control Act, Ark. Code Ann. § 8-4-101 *et seq.*, and APC&EC Regulations 18, 19, and 26, the state's regulation of the Arkansas Operating Air Permit Program impose duties upon the ADEQ to consider or control carbon dioxide emissions.

4. Greenhouse Gas Emissions

   Commenters state that greenhouse gas (GHG) emissions from the proposed Turk plant will cause serious health and environmental risks.

   The ADEQ must do its part to prevent these health and environmental threats by prohibiting, or at a minimum mitigating, the at least 5 million tons of CO_2 pollution that would result from the proposed project annually.

   There are at least three ways in which ADEQ must consider the global warming impacts associated with the proposed Turk plant: (1) as a pollutant "subject to regulation" in the BACT analysis, (2) in the BACT collateral impacts analysis, and (3) in the alternatives analysis under CAA Section 165.

   In addition, the commenter asks the ADEQ see and respond to *Considering Alternatives: The Case for Limiting CO_2 Emissions from New Power Plants Through New Source Review*, by Gregory Foote, 34 ELR 10642, 7-2004 (Attachment E)

Response:

ADEQ disagrees that it must consider global warming impacts from the Turk plant. ADEQ does not currently regulate all greenhouse gases. Neither the Clean Air Act (CAA) and corresponding Environmental Protection Agency (EPA) regulations, nor Arkansas Pollution Control and Ecology Commission regulations impose duties upon ADEQ to consider or control carbon dioxide emissions.

(1) Carbon dioxide is not a pollutant subject to regulation in the BACT analysis.

On April 2, 2007, the Supreme Court ruled in *Massachusetts v. EPA*, 549 U.S. 497, 127 S.Ct. 1438 (2007), that carbon dioxide and other greenhouse gases are pollutants under Title II of the Clean Air Act.

The case before the Supreme Court dealt only with whether EPA had the legal capacity to regulate CO_2 emissions from new motor vehicles under Title II of the Act, and if so, whether EPA had offered sufficient reasons for refusing to do so. Given the focused nature of the questions that it faced, the Supreme Court's rulings are quite narrow. The court concluded that EPA may regulate CO_2 emissions from mobile sources, not that it must. *Id.* at 1462. The Court further held that EPA had not offered sufficient reasons for refusing to determine whether it should regulate CO_2 emissions, but held open the opportunity for EPA to make that showing on remand. *Id.* Importantly, the Court did not answer whether EPA must regulate greenhouse gas emissions, and if it chooses to do so, when it must be done.

In fact, the Court went to great pains to point out that its decision does not mandate whether CO_2 should be regulated, much less how.

"We need not and do not reach the question whether on remand EPA must make an endangerment finding [the first step in the regulatory process for deciding about emissions limits mobile sources], or whether policy concerns can inform EPA's actions in the event that it makes such a finding." *Id.* at 1643.
The Court held "only that EPA must ground its reasons for action or inaction in the statute." *Id.*

The Supreme Court's decision did not automatically turn greenhouse gases into regulated pollutants. By remanding the matter to EPA, the Court implicitly recognized that CO_2 was not currently regulated and that before EPA could regulate CO_2, EPA had to take additional action. *Massachusetts v. EPA* also failed to address whether EPA, let alone any state delegated by EPA to implement the Clean Air Act, has the authority to regulate CO_2 emissions from power plants under the Clean Air Act Title I New Source Review (NSR) program.

***Massachusetts v. EPA* does not address – much less mandate – any duty that ADEQ might have to conduct BACT analysis for CO_2 emissions from stationary sources, including power plants, under Title I of the CAA.**

(2) Since the Supreme Court issued the *Massachusetts v. EPA* decision, EPA has affirmed that a Prevention of Significant Deterioration (PSD) Best Achievable Control Technology (BACT) analysis is not required for CO_2 or other greenhouse gasses. In the course of issuing a PSD permit for the Deseret Bonanza electric generating unit, EPA concluded that it "does not currently have the authority to … impos[e] limitations on emissions of CO_2 and other greenhouse gases in PSD permits." *See* Deseret Bonanza Response to Comments, pp. 5-6, available at http://www.epa.gov/region8/air/permitting/deseret.html (hereinafter referred to as

"Deseret RTC"); *but see Friends of the Chattahoochee, Inc. v. Couch*, No. 08-cv-146398 (Ga. Super. Ct. June 30, 2008) (currently on appeal).

The EPA has established a five-step, top-down process for determining emission limits for each NSR –regulated pollutant considered in a PSD permitting decision: (1) identify all potentially applicable control options; (2) eliminate technically infeasible control options; (3) rank remaining technologies by control effectiveness; (4) eliminate control options from the top down based on energy, environmental, and economic impacts; and (5) select the most effective control option not eliminated by BACT. *See Prairie State Generating Co.*, 13 E.A.D.___, PSD Appeal No. 05-05, slip opinion at pp. 14-18 (EAB Aug. 24, 2006) (summarizing and describing steps in the top-down BACT analysis). *Accord Three Mountain Power, L.L.C.*, 10 E.A.D. 39, 42-43 n.3 (EAB 2001); *Knauf Fiber Glass*, 8 E.A.D. at 129-31; *Hawaii Electric Light Co.*, 8 E.A.D. 66, 84 (EAB 1998). Thus, EPA considers the collateral energy, environmental, and, economic impacts of each BACT option at Step 4 of this analysis. This fourth step is commonly referred to as the "collateral impacts analysis."

As discussed in a Brief filed by the EPA in *Christian County Generation, LLC*, 13 E.A.D. _ , PSD Appeal No. 07-01 (2008), the CAA does not provide any guidance to permitting authorities regarding how to weigh collateral impacts when determining BACT emissions for a particular source. Therefore, the EPA has developed a longstanding interpretation that "the primary purpose of the collateral impacts clause is to temper the stringency of the technology requirements whenever one or more of the specified collateral impacts – energy, environmental, and economic-renders use of the most effective technique ineffective." *Id.*, quoting from *Columbia Gulf Transmission Co.*, 2 E.A.D. 824, 826 (Adm'r 1989). "Accordingly, the environmental impacts analysis 'is generally couched in terms of discussing which available technology, among several (considered for a source) produces less adverse collateral effects, and, if it does, whether that justifies its utilization even if the technology is otherwise less stringent' in controlling the regulated pollutant." *Id*, quoting from *Old Dominion Electric Cooperative*, 3 E.A.D. 779, 792 (Adm'r 1992).

At the first step in the BACT analysis, ADEQ considered numerous technologies for the control of pollutants subject to regulation. As previously discussed, carbon dioxide is not, at this time, a pollutant subject to regulation. Therefore, no GHG control technologies were identified at step one, nor were any required.

The collateral impacts analysis was intended to provide a mechanism for eliminating control options (previously identified in step one) that result in fewer emissions of pollutants subject to regulation, but which have other, significant, localized adverse effects based on the particular circumstances at hand. The commenter has stated that the BACT analysis is deficient for failure to consider the collateral impacts associated with carbon dioxide and other GHGs.

It is not appropriate for the Department to consider global warming and global climate change as a collateral impact in the BACT analysis, because global impacts are not the type of adverse impact contemplated by the statute or regulations and is contrary to the long-standing policy interpretation of the EPA. EPA recently explained that it has "historically interpreted the phrase 'environmental impacts' to focus on local environmental impacts that are directly attributable to the proposed facility." Deseret RTC at p. 8. Carbon dioxide is a naturally occurring substance that is emitted by most, if not all, industries, and by natural occurrences such as human breathing. Currently, carbon dioxide is not regulated under state or federal law. Consequently, there is no meaningful guidance on how limits could or should be imposed. Given the current state of the law, it would be inequitable and unjust to regulate carbon dioxide and other GHGs via the collateral impacts analysis. Even if the Department were to consider global warming as a collateral impact, the commenters have not demonstrated that ADEQ failed to consider a control technology required under BACT at the first stage, or that any remaining control technologies considered at the fourth stage would have resulted in significantly less GHG emissions than the current technology being proposed.

(3) The alternatives analysis is discussed in the following response to comments.

5. Global warming must be considered under the alternatives analysis.

   CAA Section 165(a)(2) provides that a PSD permit may be issued only after an opportunity for a public hearing at which the public can appear and provide comment on the proposed source, including "alternatives thereto" and "other appropriate considerations." 42 U.S.C. § 7475(a)(2).

   There are numerous alternatives to building the proposed new coal plant. It could be possible to build this new plant while curbing overall emissions of CO_2, through a combination of retiring older and even less efficient boilers, investments in wind or solar power, and energy efficiency measures. If ADEQ does elect to issue a Final Permit, we urge the agency to condition approval of the proposed permit on a commitment by SWEPCO to curb overall CO_2 emissions associated with providing electricity to its customers by 25 percent below 2005 levels by 2012 (i.e. meet the Kyoto Protocol reductions). This approach is consistent with Governor Beebe's stated goal for the recently formed Arkansas Global Warming Task Force to identify strategies to curb global warming emissions to 1990 levels by 2020 and 60 percent by 2050.

Response:

Section 165(a) (2) requires, among other things, that the permitting authority consider alternatives to the proposed source prior to issuance of a PSD permit. There were several alternatives proposed by the comments, including: alternative facilities, such as wind, solar, and/or use of energy efficiency measures. In addition, other comments have requested consideration of the use of geothermal power,

Integrated Gasification Combined Cycle ("IGCC") technology and design, and alternative site locations. All these alternatives will be addressed here.

Wind and Solar

The Turk plant is a 600 MW baseload facility, meaning that it is designed to operate 24 hours a day, 7 days a week. Wind and solar power are variable and not currently storable, and therefore, are not capable of supplying baseload requirements.

Geothermal

Geothermal facilities are capable of serving baseload requirements. However, it is uncertain whether the geothermal resources in Arkansas are sufficient. Significant capital investment and time would be necessary to explore for sufficient geothermal resources, and to conduct land acquisition. As a result, the baseload requirements needed by 2011 would not be available.

Alternative Sites

The site location of a power plant is determined by applicant. The Department does not dictate where such facilities should be located, nor is it required to do so by state or federal law.

IGCC

Although IGCC has significant promise, IGCC design, at the current time, is too uncertain. The technology is not as reliable, has not been demonstrated for a facility this size, is not designed for use of sub-bituminous coal, and is significantly more expensive to build.

IGCC has the promise of numerous environmental benefits, including lower SO_2, CO, VOC, particulate matter, and mercury emissions, higher efficiency, and different water input requirements and output quality. However, there are several disadvantages of IGCC given the current state of technology. Capital costs are approximately 20 to 30% higher for an IGCC plant when compared to a USCPC plant. Specifically, an IGCC plant utilizing sub-bituminous coal would cost approximately 28% more than the USCPC design. And, the only two plants currently in operation in the United States have shown performance reliability problems. In addition, performance guarantees are much more difficult to obtain for IGCC facilities, particularly for the newer design types currently under consideration in other states. Performance guarantees are crucial to financing. Several planned IGCC plants have been cancelled due to the inability to obtain financing.

The thermal efficiency of an IGCC plant is nearly identical, or slightly worse, than the USCPC plant. Thermal efficiency is a measure of the operating unit's ability to efficiently extract heat from coal (or other fuel) and convert it from thermal to mechanical to electrical energy. Greater thermal efficiency means that more electricity is generated with the same amount of coal and, consequently, lower emissions.

Currently, there are only two IGCC electricity generation units operating in the United States—the Tampa Electric Company Polk Station in Mulberry, Florida ("Polk") and the Wabash Valley Power Association's Wabash River Coal Gasification Repowering Project in West Terre Haute, Indiana ("Wabash"). The Polk facility is a 250 MW designed for using eastern bituminous coals (sometimes blending up to 55% pet coke with eastern bituminous coal). The Wabash facility is a 263 MG facility also designed for using eastern bituminous coal (and sometimes using up to 100% pet coke with additives).

At the present time, there is no operating 600 MW IGCC facility utilizing sub-bituminous coal. There was one proposed plant designed to burn sub-bituminous coals (or a blend thereof) within the 600 MW range (Stanton); however that proposal has been cancelled.

The Department requested information from SWEPCO on the emissions and cost differences between the proposed plant and all operating and/or permitted IGCC facilities in the United States. *See* SWEPCO Supplemental Information correspondence dated October 17, 2008, October 22, 2008, and October 31, 2008 (regarding IGCC).

In addition to Wabash, Polk and Stanton, the Department considered: Kentucky Power, Lima Energy, Elm Road, Taylorville, Cash Creek, and Duke Edwardsport. These are plants that have been proposed and permitted, but are not actually operating yet.

Some emissions rate data for some of the abovementioned plants could not be calculated due to insufficient information contained in the permits. For example, many of the permits for these facilities contained a heat input limit based on the heat content of the syngas, rather than the coal. The heat input of the syngas is necessarily less than that of the coal because heat is lost during the gasification process. This heat loss can approach 50%. Therefore, a coal-based lb/MMBtu rate cannot be calculated for comparison. Where the emissions rate information could be calculated, SWEPCO provided that information.

The SO2 emissions data for the two operating facilities (Wabash and Polk) had actual data for 2005, 2006, and 2007 (Wabash had SO2 emissions of 0.12, 0.09, and 0.08 expressed in lb/MMBtu, respectively and Polk had SO2 emissions of 0.16, 0.16, and 0.16 expressed in lb/MMBtu and 1.63, 1.59, and 1.71 express in lb/MWh, respectively). Thus, the actual data from the two operating IGCC facilities shows

equal or higher emissions of SO2 than the Turk limit of 0.08. The remaining IGCC plants that were considered did contain lower permit limits for SO2 (ranging from 0.01 to 0.032). However, it is questionable whether these limits can be achievable in practice.

Likewise, the actual data from Wabash and Polk show much higher emissions of NOx than the SWEPCO permit limit of 0.05. Wabash emissions of NOx for 2005, 2006, and 2007 were 0.08, 0.07, and 0.08 expressed in lb/MMBtu, respectively. Polk emissions data for of NOx was 0.06 lb/MMBtu each year.

Mercury emissions for Wabash facility could not be determined and the Polk plant reported a 1.6 lb/TBtu limit. However, the Polk facility is less efficient than the SWEPCO plant making a direct comparison to the SWEPCO 1.7 lb/TBtu limit inappropriate.

6. Carbon dioxide is a pollutant subject to regulation. Many commenters stated that Carbon dioxide is a pollutant and subject to regulation. Comments included general statements that CO_2 is harmful, costs of carbon dioxide emissions must be considered and the emissions of CO_2 need to be reduced.

Response

ADEQ disagrees with the commenter's assertions that: (1) carbon dioxide is a regulated NSR pollutant, (2) carbon dioxide is subject to regulation under the CAA (3) carbon dioxide is currently regulated under the CAA; (4) carbon dioxide is subject to regulation because of the monitoring and reporting requirements under the Acid Rain Provisions of the Act; and (5) that carbon dioxide is subject to further regulation under the act.

(1)(2)(3) Carbon dioxide is not a regulated NSR pollutant. It is not subject to regulation under the CAA and it is not currently regulated under the CAA. While *Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), held that CO_2, and other greenhouse gases are "air pollutants" under the CAA, that decision did not make CO_2 a regulated NSR pollutant.

The Clean Air Act requires PSD permits to contain emission limitations for "each pollutant subject to regulation" under the Act. CAA §§ 165(a) (4), 169(3). In its 1978 PSD rulemaking, EPA defined "'subject to regulation under this Act' [to] mean[] any pollutant regulated in Subchapter C of Title 40 of the Code of Federal Regulations for any source type." 43 Fed. Reg. 26388, 26397 (June 19, 1978) Nothing that either EPA or the Supreme Court has done since 1978 has altered that definition.

The EPA has historically interpreted the term "subject to regulation under the Act" to describe pollutants that are presently subject to a statutory or regulatory provision that requires actual control of emissions of these pollutants. The

Environmental Appeals Board (EAB) has also adopted this approach. In a case involving a proposed coal-fired power plant, the EAB dismissed arguments that a BACT analysis was required for CO_2. The EAB found that, because CO_2 is an "unregulated pollutant," "the Region was not required to examine control technologies aimed at controlling" CO_2 as part of its BACT analysis. *In re Inter-Power of New York, Inc.*, 5 E.A.D. 130, 151 (EAB 1994). Similarly, the EAB upheld a PSD permitting decision that CO_2 was not a "regulated air pollutant for permitting purposes" in *Kawaihae Cogeneration Project*, PSD/CSP Permit No. 0001-01-C, 7 E.A.D. 107, 132 (1997) because there were "no regulations or standards prohibiting, limiting or controlling the emissions of greenhouse gases from stationary sources".

Decisions by the Environmental Appeals Board consistently have held that a pollutant is "subject to regulation" only when a regulation "has been promulgated" for that pollutant – not when a regulation could be promulgated. *E.g. In re Indeck-Elwood, LLC,* **13 E.A.D. _, slip op. at 8, n.10 (EAB 2006). For example, in a 1986 challenge to a BACT determination, the EAB concluded that "EPA lacks the authority to impose [PSD] limitations or other restrictions directly on the emission of unregulated pollutants."** ***See In re North County Resource Recovery Assocs.***, **2** E.A.D. 229 (Adm'r 1986).

(4) ADEQ disagrees that CO_2 is a pollutant "subject to regulation" because of the monitoring and reporting requirements found in the Acid Rain Provisions of the Act; and (5) that carbon dioxide is subject to further regulation under the act. Section 821 of the CAA does not require any emission limits for, or restrictions of, carbon dioxide emissions and the EPA has not yet issued regulations requiring control of emissions of CO_2. EPA's interpretation is that the PSD program only covers those air pollutants actually regulated through some form of emission limit or control requirements. See 43 Fed. Reg. 26388, 26397 (June 19, 1978) (interpreting "subject to regulation under the Act" to mean "any pollutant regulated in Subchapter C of Title 40 of the Code of Federal Regulations . . . includ[ing] all criteria pollutants subject to NAAQS review, pollutants regulated New Source Performance Standards, pollutants regulated under the National Emission Standards for Hazardous Air Pollutants and all pollutants regulated under Title II of the Act regarding emission standards for mobile sources."); 57 Fed. Reg. 32250, 32264 (July 21, 1992) (for purposes of Part 70 operating permits, "[t]he term 'regulated air pollutant,' as now defined, accurately reflects all pollutants subject to a standard, regulation, or requirement."); *North County Resource Recovery Assoc.*, 2 E.A.D. 229, 230 (Adm'r 1986) ("EPA lacks the authority to impose [PSD permit] limitations or other restrictions directly on the emission of unregulated pollutants. EPA clearly has no such authority over emissions of unregulated pollutants."); NSR Manual at A.18, A20-21 (only 26 air pollutants are "regulated pollutants;" CO_2 is not included in this list); *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 162 (E.A.B. 1999) ("Not all air pollutants are covered by the PSD statutory requirements."); *In re Indeck Elwood, LLC*, 13 E.A.D. (slip op. at 8

n.10) (E.A.B. 2006) ("regulated NSR pollutants" are those for which a standard "has been promulgated").

(5) Even if carbon dioxide is a pollutant under Title I of the Clean Air Act, carbon dioxide is not yet "subject to regulation" because the EPA has not yet regulated carbon dioxide. A BACT analysis is only required for that subset of "pollutants" that are actually "subject to regulation" under the Clean Air Act. See e.g., 42 U.S.C. § 7479 (3); 40 C.F.R. § 52.21(b) (12); AR Reg. 19.903 (adopting the federal regulatory definitions). As a result, a pollutant is not "subject to regulation" under PSD unless and until EPA adopts substantive emissions limitation regulations for that pollutant. See 43 Fed. Reg. 26388, 26397 (June 19, 1978) (describing pollutants subject to BACT requirements as pollutants actually regulated under specific CAA provisions); 61 Fed. Reg. 38250, 38309-10 (July 23, 1996) (listing pollutants subject to PSD review). As there is no present emission limitation rule on CO_2, it is not a pollutant "subject to regulation" by PSD that requires a BACT analysis.

7. The BACT analysis and determination fails to address CO_2. CO_2 is a pollutant regulated under the Clean Air Act. Several commenters stated that CO_2 is required to be regulated under NSR rules.

   Commenters stated CO_2 must be regulated under BACT with specific BACT limits as well as a non-regulated pollutant, in the BACT analysis. This "collateral impacts" analysis is intended to target pollutants that are otherwise unregulated under the PSD provisions.

   A stringent output-based standard would minimize CO_2 emissions and to minimize the emissions of carbon dioxide, ADEQ should insert a permit provision requiring the project proponent to maintain a net thermal efficiency at or above 41 percent. Such a term would minimize both the emissions of regulated pollutants and the collateral emissions of carbon dioxide.

Response:

Please refer to response to comments above regarding the consideration of carbon dioxide in the BACT collateral impacts analysis.

The commenter has specifically requested that the Department include a thermal efficiency permit limit of 41% as a means of reducing carbon dioxide as part of the BACT analysis. Thermal efficiency is a measure of the operating unit's ability to efficiently extract heat from coal (or other fuel) and convert it from thermal to mechanical to electrical energy. Greater thermal efficiency means that more electricity is generated with the same amount of coal and, consequently, lower emissions.
Different design and control technologies result in different efficiencies. Efficiency is a measure of the effectiveness of a particular design. Thermal efficiency is the result of numerous factors, such as the type of control technology in

place and the type of fuel consumed. It is inappropriate for a number of reasons to require an efficiency limit as BACT. Efficiency is a measure of performance and not a "production process, method, system, or technique." The actual performance of this facility will not be known until it is operational; and it is in the applicant's best interests to operate at the greatest efficiency possible. Finally, the Department is unaware of any PSD permit that has been issued requiring a thermal efficiency limit.

8. Clean Fuels/BACT/CO_2

   Contrary to the requirements of the Clean Air Act, the agency has not considered clean fuels in its BACT analysis. ADEQ must require a lawful top-down BACT analysis for each regulated pollutant, including SO_2, NOx, PM and sulfuric acid mist, that considers the use of cleaner fuels as a way to minimize emissions of regulated pollutants and the collateral benefits associated with reducing overall CO_2 emissions as well.

Response

BACT is defined in the CAA as:

> **[A]n emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs determines is achievable for such facility through application of production processes and available methods, systems and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of such pollutant."**

42 U.S.C. § 7479(3) (referred to as Section 169).

The Sierra Club has commented that the Department was required to consider IGCC as well as "clean fuels" as part of its BACT analysis for each regulated pollutant, including SO_2, NO_x, PM, sulfuric acid mist, and CO_2. First, CO_2 is not a regulated pollutant and, therefore, a BACT analysis is not required for CO_2. As to the remaining pollutants, the Department follows EPA's interpretation on that issue discussed below.

EPA's policy reflects the Agency's longstanding judgment that limits should exist on the degree to which permitting authorities can dictate the design and scope of a proposed facility through the BACT analysis. This policy is based on reasonable interpretations of Sections 165 and 169(3) of the CAA, which recognizes that, although the permitting authority must take comment on and may consider alternatives to a proposed facility, the BACT analysis itself is conducted without changing fundamental characteristics of the proposed source.

See Deseret RTC at 11; but see Friends of the Chattahoochee, Inc. v. Couch, No. 08-cv-146398 (Ga. Super. Ct. June 30, 2008) (currently on appeal).

Sections 165 and 169 of the CAA distinguish between consideration of "alternatives" to the proposed source, and the permitting and selection of BACT for the proposed source. Section 165(a)(2) requires consideration of alternatives to the source and also "control technology requirements." By listing these separately in section 165, Congress distinguished between alternatives that would completely replace and redesign the facility on the one hand, from the "production processes and available methods, systems, and techniques," that should be considered in the BACT analysis. *See Deseret RTC* at 11. Further, the BACT statute focuses on the project that is proposed by the applicant, not the permitting authority. *Id.* Therefore, the inherent design aspects of the facility, as proposed by the applicant, are the starting point in the BACT analysis. *Id.*

Section 169 requires permitting authorities conduct the BACT analysis on a "case-by-case" basis on the "proposed facility," while also considering "application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques" that might alter the facility. *Id.* at 12. However, the statute does not provide guidance on how the permitting authority should reconcile this ambiguity. *Id.* at 13. EPA's policy against redefining the source is a reasonable interpretation of the statute that harmonizes all of its provisions. Therefore, consideration of "innovative fuel combustion techniques," or "clean fuels" are not required in the BACT analysis when they would require redesign of the proposed source. *Id.* at 14. This interpretation is buttressed by the legislative history found in the Senate committee report:

> **The Administrator may consider the use of clean fuels to meet BACT requirements if a permit applicant proposes to meet such requirements using clean fuel. ... In no case is the Administrator compelled to require mandatory use of clean fuels by a permit applicant.**

S. Rep. 101-228, at 338 (describing section 402(d) of S. 1630). EPA's policy against redefining the source was recently upheld by the Environmental Appeals Board ("EAB") and affirmed Seventh Circuit Court of Appeals. *Prairie State Generating Company*, 13 E.A.D. ___, PSD Appeal No. 05-05 (August 24, 2006) (hereinafter "*Prairie State*"); *aff'd Sierra Club v. EPA*, 499 F.3d 653, 655 (7th Cir. 2007).

> **Refining the statutory definition of "control technology"-"production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques"-to exclude redesign is the kind of judgment by an administrative agency to which a reviewing court should defer.**

***Sierra Club*, 499 F.3d at 655 (citing *Environmental Defense v. Duke Energy Corp.*, 549 U.S. 561, 127 S.Ct. 1423, 1434 (2007); *New York v. EPA*, 413 F.3d 3, 19-20 (D. C. Cir. 2005); *Alabama Power Co. v. Costle*, 636 F.2d 323, 397-98 (D. C. Cir. 1979)).**

The policy against redefining the source is only relevant when considering lower polluting processes or "clean fuels." *Deseret RTC* at 14. On the other hand, the permitting authority is not required to accept all elements of design that an applicant proposes. *Id.* A facility may not intentionally design the facility in a way calculated to make measures for limiting the emission of pollutants ineffectual. *Prairie State*, 13 E.A.D. at 30, 33-34. Furthermore, some design changes are within the scope of BACT. *See Deseret RTC* at 14 (citing *Knauf Fiber Glass*, 8 E.A.D. at 136). The policy against redefinition would not allow the permitting authority to rule out "add-on controls." *Id.* at 12, 14 (citing *Prairie State*, 13 E.A.D. at 30).

The Seventh Circuit Court of Appeals has explained:

> **The Act is explicit that "clean fuels" is one of the control methods that the EPA has to consider. Well, nuclear is clean, and so the implication, one might think, is that the agency could order Prairie State to redesign its plants as a nuclear plant rather than a coal-fired one, or could order it to explore the possibility of damming up the Mississippi to generate hydroelectric power, or to replace coal-fired boilers with wind turbines. That approach would invite a litigation strategy that would make seeking a permit for a new power plant a Sisyphean labor, for there would always be one more option to consider. ... [T]he extreme implications of such a strategy[] [] would stretch the term "control technology" beyond the breaking point and collide with the "alternatives" provision of the statute.**

***Sierra Club*, 499 F.3d at 655. In that case, the applicant proposed to use coal that was co-located with the plant and which happened to be high in sulfur content. This type of plant is called a mine-mouth plant. Sierra Club argued that the permitting authority should have considered a lower sulfur coal in the BACT analysis. Such consideration was not required because the primary purpose of the proposed facility was to use the coal source located nearby and requiring importation of other, albeit better, coal would have been contrary to the fundamental purpose of the proposed facility. *Id.* at 656-57.**

Although the Turk plant is not a mine-mouth plant, it will utilize the low sulfur coal. The commenter has not pointed out, and the Department has not found, a commercially available source of lower-sulfur coal. As for consideration of alternative types of processes such as IGCC, or fuel types, such as natural gas, nuclear, solar, wind, and/or hydro-power, all these would require a redefinition of the source and, therefore, are not required in the BACT analysis.

9. Integrated gasification combined cycle (IGCC)

The application and draft permit fail to consider integrated gasification combined cycle technology (IGCC) as part of the required BACT analysis. The BACT determination fails to properly evaluate integrated gasification combined cycle (lGCC) as an available method.

The U.S. EPA has withdrawn the December 13, 2005, memo, which SWEPCO relied upon to suggest that IGCC should not be included in a BACT analysis for a PC boiler. See EPA Notice of Proposed Settlement Agreement, 71 Fed. Reg. 61,771 (October 19, 2006).

Response:

The settlement language EPA agreed to in withdrawing the referenced letter is:

EPA agrees and stipulates that the December 13, 2005 document is not final agency action and creates no rights, duties, obligations, nor any other legally binding effects on EPA, the states, tribes, any regulated entity or any person

EPA does not state that they believe the decision to be in error. In fact, Region 8 of EPA reiterates the argument in consideration of IGCC: "[T]his alternative process would represent a redefinition of the source proposed by the applicant and thus need not be listed as a potentially applicable control option at step 1 and evaluated further in the BACT analysis for this type of facility." ***Deseret RTC*** **at 10.**

Although the Deseret project is for a CFB Boiler utilizing pulverized waste coal, the characterization on Page 15 still holds for the SWEPCO case.

An IGCC facility uses a chemical process to first convert coal into a synthetic gas and to fire that gas in a combined cycle turbine. "Final Report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," EPA-430/R-06/006, July 2006. The combined cycle generation power block of an IGCC process employs the same turbine and heat recovery technology that is used to generate electricity with natural gas at other electric generation facilities. Thus, this portion of the IGCC process is very similar to existing power generation designs that EPA has agreed would redefine the basic design of the source when an applicant proposed to construct a pulverized coal fired boiler. ***SEI Birchwood Inc*****, 5 E.A.D. 25 (1994);** ***Old Dominion Electric Cooperative Clover, Virginia*****, 3 E.A.D. 779 (Adm'r 1992). Furthermore, the core process of gasification at an IGCC facility is fundamentally different than a boiler. Coal gasification is more akin to technology employed in the refinery and chemical manufacturing industries than technologies generally in use in power generation (i.e. a controlled chemical reaction versus a true combustion process). Use of coal gasification technology would necessitate different types of expertise on the part of the applicant and employees to produce the desired product (electricity). Thus, these fundamental differences in equipment design are sufficient to conclude that the IGCC process would redefine the proposed source.**

Therefore, ADEQ did not consider IGCC in a BACT analysis, nor was it required to do so.

However, in the same decision, EPA cites Section 165(a) (2) of the Clean Air Act which requires, among other things, that the permitting authority consider alternatives to the proposed source prior to issuance of a PSD permit. IGCC is one such alternative that was raised during the public comment period and that was considered by the Department. Please refer to comments above on alternatives, including IGCC.

Best Available Control Technology (BACT)

10. General Comments

One commenter made generic comments that the application emission limits do not satisfy BACT and included generic reasons showing why BACT was not properly followed including the scope of technologies considered was too limited, lower limits were incorrectly excluded and the sources consulted were too limited.

The proposed best available control technology ("BACT") analysis is flawed and insufficient. BACT requires a comprehensive analysis of all potentially available emission control measures, expressly including input changes (such as use of clean fuels), process and operational changes, and the use of add-on control technology. Additionally, it requires that a new source comply with emission limits that correspond to the most effective control measures available, unless the source can affirmatively demonstrate that use of the most effective control measures would be technologically or economically infeasible.

BACT must be based on levels achieved in the past and ADEQ should have looked at actual emission data; BACT must be based on the maximum level of reduction possible, ADEQ must consider control efficiencies and not just controlled emission rates in its analysis, and; no data was used in application to justify step 3 in the top down BACT analysis.

Response:

The commenter generalizes but then further elaborates on specifics. These specifics are discussed in later comments on BACT.

11. BACT limits need to be expressed in mass per power generated to promote efficiency and thus lower emission rates.

Response

The ADEQ agrees that greater efficiency will result in lower emission rates and limits on an output basis. However, it would be inappropriate to compare emission limits based on output alone. Fuel type, boiler design, individual characteristics of a plant and even the energy demand of different types of air pollution control equipment can affect such an analysis. The commenter presented output based limits calculated from available information but did not provide any details as to the method of calculations, the details of these facilities, averaging times, or even which limits are purported to be lower than the draft SWEPCO permit. A cursory review of the information indicates limits possibly both above and below the SWEPCO proposed limits.

The proposed boiler is an ultra supercritical boiler. Based on Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies EPA-430/R-06/006 July 2006 page ES-7, Exhibit ES-1, Generation Performance Comparison, an ultra supercritical boiler has the highest efficiency of any PC boiler. Thus, in consideration of any emission limits, an USCPC boiler would result in lower rates on an output basis if one evaluated limits based on input (i.e. emissions expressed as lbs/MMBtu).

Even though the Department may agree that greater efficiency will result in lower emissions on an output basis, there is no requirement for BACT limits to be explicitly expressed in output based units. Most coal fired power plants have emission rates expressed in terms of Btu input and are readily comparable for establishing BACT.

Lastly, continuous emission monitors and testing are standardized and readily report values based on Btu input. While not impossible, output based limits would add a complexity and uncertainty to monitoring and establishing permit limits. Because the ADEQ would need to consider the power generation side of the plant, it would be necessary to somehow relate power generated to Btu input. Averaging times would need to be reconsidered and additional consideration for times of start up/shut down of the generator. The Department would also somehow need to compare BACT rates expressed in Btu and establish equivalent numbers in terms of output.

For these reasons, limits based on output are not included in this permit.

12. BACT limits need to be established and enforceable on a mass per time and mass per Btu basis.

Response

The Department agrees and will establish both limits as PSD limits. Although the facility will have some CEMs, compliance with other emission rates are demonstrated through a stack test only. In order to comply with these rates on an ongoing basis, the facility must not only meet the stated limits in the stack test, but

also not operate the facility above the production levels stated in the application. Therefore a 6000 MMBtu/hr limit on the main boiler, on a 24 hour average will be included in the permit as a compliance mechanism.

13. Particulate matter (PM) limits should include both "front-half" (filterable) and "back-half" (condensable) emissions.

Response

PM/PM_{10} limits do include front and backhalf emissions as evidenced by required test methods in the permit, i.e. inclusion of Method 202 for PM and PM_{10}.

14. The BACT analysis failed to consider catalytic oxidation, and if it had, it would have concluded that catalytic oxidation is technically feasible.

Response

An oxidation catalyst for CO and VOC was considered. Details are contained in the BACT analysis of the application. By the footnote included in this comment, the commenter is referencing an oxidation catalyst for NO. The footnote referenced in the article cited states it is a "low cost alternative NOx control method ... based in the use of existing or new wet flue gas desulfurization (FGD) scrubbers ...that could achieve a 65 µg/MJ (0.015 lb/MMBtu) NOx emission rate."

The Turk plant will be equipped with a catalytic reduction system to reduce emissions below the stated limits of the referenced NO catalyst. There is no reason to consider the inferior technology in the BACT analysis.

NOx BACT Issues

15. The application improperly rejects lower permitted NOx limits. Specifically, limits in the Trimble, Desert Rock, Thoroughbred permits. In addition, several permits with lower permitted NOX limits were omitted from consideration, specifically Newmont, Nevada, Roundup Montana, and Spruce Texas.

Response

The permit for Trimble states the NOx emission rate in a pounds per day limit. Using the facility's rated input as stated in the application, this would equate to 0.05 lb/MMBtu if operated at maximum rate. However, the facility is only limited to the daily mass emission rate, not the 0.05 performance rate. ADEQ does not deem this sufficient to qualify as a lower permitted limit.

The Desert Rock permit contains 0.060 and 0.05 lb/MMBtu on a 24 hour and annual basis, respectively. However, the permit also allows for a revision to these limits if

they are not deemed feasible after an optimization period. This leaves the exact limit in question. ADEQ chooses not to follow such a path and rather establish a fixed limit.

The Thoroughbred permit includes a 0.07 lb/MMBtu limit on a 24 hour basis that the ADEQ does consider relevant. Round Montana similarly contains the same limit.

The Newmont permit contains a 0.067 lb/MMBtu limit on a 24 hour basis that the ADEQ also considers relevant.

The Spruce Texas permit contains a 0.069 lb/MMBtu limit on a 24 hour basis that the ADEQ also considers relevant.

SWEPCO has agreed to meet a 0.067 lb/MMBtu on a 24 hour basis limit during normal operations and a 420 lbs/hr on a 24 hour basis limit at all times. Normal operations are defined as any periods at which the unit is generating 300 MW or more of electricity. SWEPCO claims that the nature of an Ultra Super Critical boiler requires a longer start up time before the catalyst can be brought on-line, but since the unit will be at reduced loads, the mass emission rate (lb/hr) will still be met. The 30 day NO_x limit will be removed from the permit since it is less stringent than the new 24 hour standard.

This revised limit assures that the BACT limit is at least as stringent as a previously permitted source.

16. Lower NOx limits have been achieved based on actual NOx emission data

Response

There are many considerations in establishing a BACT limit. Not all these considerations are reflected in data from the two years of actual operation of the facilities provided by the commenter. Limits must be met over the lifetime of the unit, performance changes over age and with maintenance of units, etc. In addition, a facility may have actual emission rates lower than BACT for other reasons not reflected in the BACT analysis. For these reasons, use of actual data to establish emission rates is not always the best indicator of what can be achieved over time.

The Department has discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies ever reached based on the absence of data showing that the more stringent limit has been consistently achieved over time. *See In re Newmont Nevada Energy Investment*, LLC, 12 E.A.D. 429, 430-31 (2005). Fluctuations in actual data tend to show that the optimal control efficiency cannot always be achieved in practice. *Id.* At 441.

ADEQ has reviewed the data provided. Even assuming ADEQ agreed that limits could be established on such a basis, none of the facilities presented in the comment have actual emissions that are consistently lower than the revised SWEPCO limit of 0.067 lbs/MMBtu on a 24 hour basis. All would have exceeded the value at multiple times.

17. Lower NOx limits have been guaranteed by vendors

Response

The provided information is not actual vendor guarantees but rather pages from some unspecified design sheet, meeting notes and presentation information. The information does not contain sufficient details such as averaging times, costs or other items for any comparison. Additionally, one exhibit stated a possible limit but then qualified it based on specific source parameters. Statements that the vendor had "several units" operating at a given rate fail to address the vendor's other operating units that are presumably operating at different (higher) rates.

The information provided is not sufficient to question the proposed BACT limit.

18. The BACT analysis is flawed in that it failed to consider combinations of technologies including LNB/OFA combined with SCR, instead listing LNB/OFA as the baseline.

Response

The facility will be equipped with LNB/OFA and SCR. LNB/OFA reduces the amount of NOx that the SCR must control and is standard design. Assuming a boiler emission rate without LNB/OFA and then assigning efficiency to each technology separately is impractical and serves no purpose. Limits and guarantees are based on the combination of equipment and not separate performance.

19. The permit fails to establish NOx BACT based on the maximum degree of reduction.

Response

The permit does establish the NOx limit based on the maximum degree of reduction and in accordance with BACT. The commenter proposes that the emission rate must be calculated based on the reduction achievable by individual control devices. The commenter then establishes uncontrolled emission rates and control equipment performance to arrive at a proposed final emission rate in the range of 0.02-0.03 lbs/MMBtu.

The methodology makes many assumptions that are not well documented. Uncontrolled emission rates are estimated, partially on the assumption that a USCPC boiler would have a lower uncontrolled rate than other sources. No

consideration or discussion of averaging times or variability is included. The analysis combines the emission analysis of two separate reports to arrive at the emission rate. Reviewing one of the documents referred to on SCR not only states that 90% efficiency is being achieved, but also lists emission rates in the range of 0.041 to 0.070 lbs/MMBtu. There is no reconciliation between the commenters assertion of lower rates using this 90% efficiency and the (higher) outlet emission rates in the report.

ADEQ established the emission rate based on the maximum degree of reduction considering the controls in combination and the resulting emission rate and other BACT issues. It is not necessary to establish individual control efficiencies and derive emission rates from that.

20. The permit fails to consider the impact of boiler technology in selecting BACT limit.

Response

The commenter states that an USCPC boiler would have higher efficiencies and thus lower emission rates. While this is true on an output basis (MW), this is not true on an input (Btu) basis. The efficiency in a USCPC boiler is on the conversion of the thermal energy to electricity, not on the combustion efficiency. In that regards there is no evidence for lower emission rates on a lb/MMBtu basis as established in the permit.

SO_2 BACT Issues

21. Sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) limits do not reflect best available control technology, and are higher than recently permitted similar sources, including Western Farmer's Electric Cooperative's Hugo Unit No.2, in southeastern Oklahoma with a permit limit 30 day average SO_2 emission rate of 0.065 lb/MMBtu.

    The SO_2 BACT analysis improperly rejects wet flue gas desulfurization. The application does not demonstrate unique circumstances, the alleged adverse impacts of wet FGD Are exaggerated, misleading, and erroneous and the incremental cost effectiveness is not valid. Additionally the benefits of wet FGD include reliability, lower emission during maintenance and higher SO_2 removal efficiency, among others listed

Response

The Western Farmer's Electric permit has since been voided and the facility was not constructed. The proposed SWEPCO BACT limit for H_2SO_4 emission has been revised to 0.0042 lbs/MMBtu as a result of other information and comments presented. This is further detailed in responses in this document.

The proposed BACT limit has been lowered to a 0.08 lb/MMBtu SO_2 30-day average emission limit with a 480 lbs/hr 24 hour limit. Both the 480 lb/hr limit and the 0.08 lb/MMBtu limit apply at all times. The short term limit is necessary to assure impacts are consistent with presented modeling. The long term limit allows flexibility and is consistent with other permitted coal fired power plants. Start up and shut down are included in both these limits and do not have separate allowances. ADEQ has also incorporated an additional SO_2 emission limit of 0.065 lbs/MMBtu on a 30 day rolling average when combusting coal with a sulfur content less than or equal to 0.045%.

Typically, wet flue gas desulfurization has been used on high sulfur coals and dry FGD on lower sulfur coals, including PRB. Recently, wet FGD has appeared on some low sulfur PRB permits. The comments make the statement that BACT has been established as wet FGD by other permit decisions for this type of application and/or that dry FGD has not been adequately shown to be BACT due to incorrect consideration of wet versus dry FGD.

Permitted/Existing Facilities

ADEQ researched permits and applications with possibly lower SO_2 emission rates. None of these permits has changed our determination that the proposed SO_2 Dry FGD is not BACT, however ADEQ has incorporated an additional SO_2 emission limit of 0.065 lbs/MMBtu on a 30 day rolling average when combusting coal with a sulfur content less than or equal to 0.045%. It should be noted that there are many other permits issued for facilities essentially identical to SWEPCO's Turk plant that are permitted for dry FGD and higher SO_2 rates than that proposed for the Turk plant. The permits with possibly lower rates are specifically,

> Western Farmer's Electric (utilizing PRB coal, referenced in the comment) selection of wet FGD admittedly did not consider economic costs. See Evaluation of Permit Application No. 97-058-C (M-2) (PSD),Western Farmers Electric Cooperative, Hugo Generating Station January 29, 2007 pages 37-38. The applicant needed to resolve Class I SO_2 issues and thus proposed wet FGD. Note that this permit has since been voided and the unit was not constructed.
>
> The Desert Rock facility is a mine-mouth PC boiler permitted (not yet constructed) with wet FGD (0.060 lb/MMBtu, averaged over a 24-hour block period). The permit was proposed on July 27, 2006, and it was issued on July 31, 2008. The proponent of the facility states in the application that the proposed rate is beyond BACT. From the May 7, 2004 Desert Rock Energy Facility: Supplemental PSD Permit Application:
>
>> 4.3.1.5 Summary of Pulverized Coal-fired Boiler BACT for SO_2
>> Steag is proposing to limit SO_2 emissions to 0.06 lb/MMBtu as a 24-hr average by burning low sulfur western coal and using a wet limestone

flue gas desulfurization system. This proposed emission rate is lower than any other project listed in EPA's RACT/BACT/LAER Clearinghouse, except for AESPuerto Rico, which was previously discussed. Steag's proposed emission limit of 0.06 lb/MMBtu as a 24-hour average is much lower than the two most recent permits which are the Roundup Power Project in Montana (07/21/03) and the Longview Power Project in West Virginia (draft 12/04/03). Both of these projects have SO_2 permit limits of 0.12 lb/MMBtu as 24-hour averages or 100% higher than the proposed Desert Rock Energy Facility. Therefore, Steag has made a conscious decision to achieve even lower SO_2 levels and this level of control is concluded to go beyond BACT for SO_2 from the proposed Desert Rock PC boilers.

Longleaf Energy Associates, LLC (LS Power Development, LLC) Georgia – This facility is a dry FGD system permitted to burn a mix of sub bituminous and bituminous coals from different regions. The facility has a 24 hour limit of 0.12 lbs/MMBtu and 30 day limits from 0.065 to 0.105 based on coal SO_2 input with the 0.065 limit applying to coal with an SO_2 input less than 1 lbSO_2/MMBtu. This unit is permitted but not yet constructed or operating.

LS Power- White Pine Nevada – this unit will be a dry FGD with 0.065 to 0.09 lb/MMBtu 24-hr average depending upon the sulfur content of the coal above or below 0.045%. This permit was issued draft on December 28, 2006.

Newmont Nevada – this unit is a dry FGD with limits of 0.065 and 0.09 lbs/MMBtu, 24 hour basis depending on coal sulfur content below or above 0.45% sulfur (approximately 1.125 lbs SO_2/MMBtu). This facility is permitted (May 5, 2005) and is under construction

Florida Power and Light – information indicates that two applications were submitted but are no longer active. These had a limit of 0.04 on a 30 day basis with Wet FGD. ADEQ does not consider these relevant.

Two recent applications have occurred since the SWEPCO draft permit was issued. Alliant Energy Iowa applied for a permit to combust PRB with up to 10% Eastern Bituminous and some biomass with limits of 0.06 lb/MMBtu or 98% control with a 0.08 upper limit with wet FGD. The most resent submittal by the applicant is for a revised rate of 0.031 lbs/MMBtu on a 30 day average. Waterloo (Black Hawk) LS Power Iowa applied for a permit to combust PRB with some biomass and proposed limits of 0.065 – 1.0 lb/MMBtu on a 30 day average based on sulfur content with wet FGD. This application has not yet been reviewed by the agency. No draft permit is yet issued for either of these proposed facilities. The permits need not be considered.

Nevada Sierra Pacific & NV Power- Ely Energy Center (draft permit October 29, 2007) and Toquop Energy Project draft permit December 21, 2007), Nevada – these are proposed PC boilers using PRB coal. These permits are in the draft stage. Both these permits have identical language in the permit. From CLASS I APPLICATION REVIEW, FOR Toquop Energy, LLC, Toquop Energy Project, Near Mesquite, Nevada Class I Operating Permit to Construct AP4911-1146, (FIN # A0381) (Aircase # 07AP0270):

> **5.1.3 SO_2 BACT Analysis**
> **Toquop has selected wet quicklime de-sulfurization and hydrated lime injection located prior to the fabric filter, in combination with low sulfur coal as the BACT technology for controlling SO_2 emissions from the PC boiler. It is the BAPC's position that BACT for SO_2 emissions from a PC Boiler located in the western United States is dry scrubbing. Toquop's proposed use of wet scrubbing to control SO_2 emissions from a PC Boiler is above and beyond BACT technology, and may, more appropriately, be considered LAER technology. Toquop is proposing an emission limit of 0.06 lb/MMBtu on a 24-hour rolling average for the PC boiler. This technology is consistent and the proposed emission limit is lower than BACT selected in other similar projects on the RBLC database and EPA Region 4's PC Boiler Tables.**

San Antonio Calaveras Lake Station, Texas has limits of 0.1 lb/MMBtu (30-day average) 0.06 lb/MMBtu (12-month rolling average). The SWEPCO short term limit is stricter than this short term limit; SWEPCO does not have a long term limit.

Wet versus Dry FGD BACT analysis

The ADEQ made a determination that dry FGD was BACT based on the adverse impacts associated with wet FGD and the associated higher cost of wet FGD. These considerations included, among others, water usage and disposal issues, energy considerations, and waste disposal costs. The commenter has submitted case by case counter arguments regarding these adverse impacts and further stated that since these impacts are not unique to SWEPCO, the technology cannot be discounted; all wet FGDs have the same impacts and they are therefore not a consideration.

ADEQ asserts that the case for wet FGD as BACT for PRB has not yet been made and therefore SWEPCO need not make a case for adverse impacts being unique to SWEPCO. That is, SWEPCO is not discounting an established BACT technology for PRB.

In the BACT decision, economics and other impacts are allowable considerations. The commenters counter arguments for the adverse impacts range from outright

repudiation of the adverse impacts, such as sulfuric acid emission changes, to alternative values based on published data, such as water usages, or admitting the impacts, but stating they are not excessive, such as increased disposal costs but stating that the wet FGD product can be used in a non-existent manufacturing facility. As a whole, the commenters arguments do not discount the additional impacts or costs of wet FGD.

The ADEQ has determined that these additional impacts and costs are sufficient to discount wet FGD, especially in light of the dry FGD emission limits of 0.08 and 0.065 lbs/MMBtu.

22. The BACT determination did not consider clean fuels as a control option. SWEPCO Turk facility is proposing a BACT limit based on higher sulfur PRB coal than any other such facility that has been permitted in the past five years. The draft permit assumes that the proposed boiler will continuously fire design coal containing 1% sulfur with a heat content of 8,000 Btu/lb, which amounts to 2.5 lb SO_2/MMBtu. Petroleum coke also should have been considered, but was not. Further, the boiler is being designed to use natural gas for startup and flame stabilization. Thus, the boiler could be operated to co-fire natural gas to lower SO_2 emissions. A BACT limit must be set based on the lower emissions achievable by mixing natural gas with coal. These cleaner fuels must be considered in a BACT analysis.

Response

Clean fuels are discussed in a previous comment and response.

The facility is designed and will be permitted to use PRB coal. Based on similar permits discussed in a previous response, ADEQ has incorporated an additional SO_2 emission limit of 0.065 lbs/MMBtu on a 30 day rolling average when combusting coal with a sulfur content less than or equal to 0.045% by weight.

Petroleum coke use or co-firing natural gas would fundamentally change the source. A boiler designed for start up/flame stabilization with natural gas does not have the same design, economics and parameters as a co-fired gas/coal unit; such a scenario would be a fundamentally different unit. EPA has long maintained the position that requiring consideration of a natural gas or other fuel fired plant in place of a coal plant is outside the scope of BACT. This petroleum coke or natural gas/coal combination is a variation on the same scenario and need not be considered as it fundamentally changes the source.

23. The BACT SO_2 limits must account for typical low sulfur PRB coal, rather than worst-case design coal. Limits must be set based on including a control efficiency in the permit, or by setting tiered BACT limits based on the sulfur content of the coal. This is essential to prevent a facility from operating its scrubber below the maximum degree of reduction determined to be BACT.

Response

The facility is designed and will be permitted to use PRB coal. Based on similar permits discussed in a previous response, ADEQ has incorporated an additional SO_2 emission limit of 0.065 lbs/MMBtu on a 30 day rolling average when combusting coal with a sulfur content less than or equal to 0.045% by weight.

24. The geographic scope of the BACT analysis was improperly limited. This restriction eliminated some of the lowest permitted and demonstrated SO_2 limits, e.g., AES Puerto Rico, Newmont, NV, and Shinko Kobe in Japan.

Response

AES Puerto Rico is a CFB facility burning Columbian coal with a Circulation Dry Scrubber (CDS) and lower permitted emission limits than the proposed SWEPCO unit. The basic boiler is different and the commenter provided no information that the situations are comparable.

Newmont Nevada is discussed in a previous response.

The Shinko Kobe plant in Japan is as the commenter states, in "polluted areas, corresponding roughly to our nonattainment areas." It employs a "Chiyoda" scrubber system. This type of wet scrubber system is discussed in subsequent comments. The commenter says Shinko should be considered as a permitted unit meeting lower limits. As a type of wet scrubber, ADEQ rejected this and other units as having the same adverse impacts and economics. In addition, as a unit in a "non-attainment" area, other economic considerations beyond BACT drive such controls and emission limits.

25. NEVCO Sevier, Desert Rock, Intermountain Unit 3, Omaha Public Power's Nebraska 2, City Utilities, City of Springfield, Western Farmers and City Public Services of San Antonio units were improperly eliminated from consideration.

Response

NEVCO Sevier is a CFB boiler design as opposed to the PC design of Turk and was discounted on that reason. CFB are a fundamentally different design than a PC boiler and are typically smaller, the NEVCO project is 270 MW. Desert Rock has been discussed above and Intermountain Unit 3, Omaha Public Power, City of Springfield has an SO_2 limit (0.095 lbs/MMBtu) higher than the proposed SWEPCO limit of 0.08 lbs/MMBtu and thus need not be considered further.

Western Farmers and Public Services of San Antonio are discussed in previous responses.

23. Lower SO_2 limits have been achieved including AES Puerto Rico

Response

AES Puerto Rico is a CFB facility burning Columbian coal with a Circulation Dry Scrubber (CDS) and lower permitted emission limits than the proposed SWEPCO unit. The basic boiler is different and the commenter provided no information that the situations are comparable.

24. Lower SO_2 limits have been achieved based on EPA CEMS data

Response:

There are many considerations in establishing a BACT limit. Not all these considerations are reflected in data from two years of actual operation. Limits must be met over the lifetime of the unit, performance changes over age and with maintenance of units, etc. In addition, a facility may have actual emission rates lower than BACT for other reasons not reflected in the BACT analysis. For these reasons, use of actual data to establish emission rates is not always the best indicator of what can be achieved over time.

The Department has discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies ever reached based on the absence of data showing that the more stringent limit has been consistently achieved over time. *See In re Newmont Nevada Energy Investment*, LLC, 12 E.A.D. 429, 430-31 (2005). Fluctuations in actual data tend to show that the optimal control efficiency cannot always be achieved in practice. *Id.* At 441.

ADEQ has reviewed the data provided. Even assuming ADEQ agreed that limits could be established on such a basis, none of the facilities have actual emissions that are consistently lower than 0.08 lbs/MMBtu on a 24 hour basis. SWEPCO will have an equivalent short term limit (420 lbs/hr, 24 hour basis) for all normal operations.

All facilities referenced in the comment would have exceeded the value at multiple times.

25. Lower SO_2 limits have been achieved outside of the United States

Response

The commenter only references Shinko which is addressed in a previous response.

26. Vendor information should have been considered

Response

BACT does not require the lowest emission rate achievable. It is a consideration of all the elements contained in the BACT definition. The documents referenced are not guarantees; they are technical papers or in one case a sales brochure. They make no statements as to what is BACT or even consider all the issues that are contained in a BACT determination. One document is specific to the Wet FGD system and does not even consider other technologies.

SWEPCO does rely on vendor guarantees in establishing the emission rate. Nothing in the information provided changes the Department's determination of BACT.

27. The BACT analysis omits viable technologies, wet and dry scrubber types are combined into two types when there are actually many variations and types. Second, the list of FGD technologies omits several that do not fall into either class. Third, combinations of control options were not considered. The BACT analysis omitted sorbent injection, circulating dry scrubber, various wet scrubbers, ECO system.

Response

SWEPCO discussed these issues in an October 17, 2008, Supplemental Information document.

Many of these technologies are either in development or only applied on a small scale and are not applicable to a base load 600 MW unit. In other cases, they are variations on the wet or dry scrubber design with the same advantages or disadvantages.

ADEQ has reviewed the information and determined that consideration of these technologies does not change the BACT determination.

28. The BACT analysis omits combinations of technologies

Response:

The commenter states that combinations of technologies must be considered in the BACT analysis. Specifically clean coal technology in combination with other technologies, the E-LIDS process, an Alstom integrated dry and wet scrubber, and Sorbent injection with FGD, among others.

SWEPCO elaborated on these issues in an October 17, 2008, Supplemental Information document. In this document, these alternatives are discounted as inferior technologies, experimental or not available for the Turk project.

ADEQ has reviewed the information and determined that consideration of these technologies does not change the BACT determination.

29. The BACT analysis did not correctly evaluate control efficiencies. The SO_2 BACT limit is based on an SO_2 removal efficiency of 95.5% and a coal sulfur content of 2.5 lb/MMBtu. The 95.5% value is buried in an appendix with no discussion or justification provided for this choice. In Step 3 of the top-down process, the applicant reports that wet FGD and dry FGD have the same upper bound SO_2 control efficiency of 90%. Thus, in response to comments, ADEQ should present and support SO_2 control efficiencies for all types of scrubbers that are evaluated. A higher control efficiency than 95.5% would have been reported had a thorough review of available sources been conducted

Response

In step 3 on page 6-12 of the application, the efficiencies are listed for ranking purposes. Wet FGD is listed as >90% and dry FGD as 80-90%+. Both are referenced with the source of the data and the design values used by SWEPCO in the application. Wet FGD is appropriately identified as the higher control option.

The issue of control efficiency used is most relevant in the determination of cost per ton of SO_2 control or incremental cost associated with wet versus dry FGD. These control efficiencies are used in the cost estimates of Appendix D of the application. The 95.5 efficiency is a high end estimate for dry scrubbing and would underestimate cost on a per ton of SO_2 removed. The 98% efficiency is a high end for wet FGD. The commenter references an upper control efficiency of 99% based on one facility in the US and "others" in Japan and "planned" in the US.

The stated efficiencies are acceptable in evaluating BACT and costs.

30. Even if SO_2 BACT is established based on a dry scrubber, the limit must be lower than 0.10 Lb/MMBtu and based on coal sulfur content and scrubber efficiencies (reduction).

Response

The facility is designed and will be permitted to use PRB coal. SWEPCO has proposed a lower limit of 0.08 lbs/MMBtu. Based on similar permits discussed in a previous response, ADEQ has incorporated an additional SO_2 emission limit of 0.065 lbs/MMBtu on a 30 day rolling average when combusting coal with a sulfur content less than or equal to 0.045% by weight.

31. BACT is not achieved for CO and VOC emissions from PC boiler

The application reports a range of previous BACT determinations for both CO (0.10 – 1.26 lb/MMBtu) and VOCs (0.002-0.18 lb/MMBtu). The Application does not explain why the lowest reported CO and VOC limits do not constitute BACT in this instance. Second, Turk will use an ultra supercritical boiler. An ultra supercritical boiler is more efficient than a subcritical boiler, or the so-called standard PC boiler, and thus is able to achieve lower emissions, including lower CO and VOC.

Response:

There is no requirement that BACT be the lowest established permit limit. CO and VOC are not specifically controlled by any post combustion emission controls, though they are affected by the same combustion design consideration for NOx. The SWEPCO Turk plant will have the lowest permitted rate found for a PC boiler.

The efficiency in a USCPC boiler is derived from the thermal efficiency, not any stated higher or better combustion efficiency, though this may also occur. There is no reason to assume an USCPC boiler will have a lower emission rate on an input basis.

SWEPCO has proposed a revised VOC limit of 0.0025 lb/MMBtu as part of the 112(g) permit. This limit is lower than all but two reported limits (0.002 and 0.0024) and the vast majority of limits are higher than 0.0025. The two lower limits represent different types of boilers (CFB).

The SWEPCO CO limit is 0.15 lbs/MMBtu. The only lower permitted limit is 0.1 lbs/MMBtu found for two CFB and one PC unit (Thoroughbred) which is a bituminous fired unit.

32. BACT is not achieved for PM_{10} emissions from PC boiler.

a. The Application does not contain a top-down BACT analysis for total PM_{10}, comprising the sum of filterable plus condensable particulate matter, but rather only an analysis for filterable particulate matter ("PM"). Total PM_{10} is a regulated PSD pollutant and a BACT analysis must be performed for it.

   However, instead, EPA suggested BACT limits of 0.012 lb/MMBtu for filterable PM_{10} and 0.02 lb/MMBtu for total PM_{10}. The Applicant agreed to the former, but not the latter. Instead, SWEPCO advocated a total PM_{10} limit of 0.025 lb/MMBtu. 4/26/07 Gaus E-Mail, Comment II. Apparently, ADEQ went along without doing an independent investigation, claiming this limit is "consistent with those found at similar facilities."

b. Total PM_{10} is the regulated PSD pollutant. The regulated pollutant for purposes of a BACT determination is total PM_{10}, comprising the sum of filterable and condensable PM_{10}. The Application does not contain a BACT analysis for total PM_{10}. The PM_{10} BACT limit in the draft permit was selected through negotiation with the Applicant. Negotiation is not a substitute for a top-down BACT analysis. The ADEQ should require that SWEPCO perform a top-down analysis for total PM_{10}.

c. Lower total PM_{10} limits have been permitted and achieved

The applicant and ADEQ provide no support for its assertion that BACT for PM_{10} is an emission limit of 0.025 lb/MMBtu. Lower PM_{10} limits have been set in recent permits and achieved in stack tests.

Response

In the recent issuance of $PM_{2.5}$ NSR, EPA has suspended the requirement for condensable evaluation and testing. The rational was that the test methods were not sufficiently reliable to establish, test or justify limits. States could in the interim before adopting the rules, maintain condensable limits if they relied upon them in their SIP. Arkansas is not one of those states and has as a matter of practice, stopped requiring the evaluation of condensable emissions.

In any event, there are no condensable specific controls that need to be considered in a BACT analysis since they do not exist. ADEQ properly evaluated and set limits based on filterable PM_{10} with condensibles considered in the total emission rate. Separate limits for both filterable and total PM_{10} (filterable plus condensable) are contained in the permit.

Facilities have only recently been required to test for the condensable portion of particulate emissions so actual emission data is scarce. During investigation of the 112(g) application, ADEQ obtained test results from two operating facilities that show actual emission rates of total PM_{10} of 0.025 to 0.031 lb/MMBtu. The commenter provides test data for other permitted units of 0.0044 to 0.170 lb/MMBtu. These values, as limited testing on new equipment, demonstrate that the proposed limit of 0.025 lb/MMBtu total is not unreasonable.

33. BACT is not achieved for sulfuric acid mist emissions from PC boiler. The draft permit sets a BACT emission limit for sulfuric acid mist (SAM or H2SO4) of 0.006 lb/MMBtu based on a 3-hour average. This limit is not based on a reasoned top-down BACT analysis. The analysis only considers wet and dry FGD. Low SO_2 to SO_3 conversion SCR needs to be considered, SCR catalyst washing should be considered, air heater additives and combinations of all these need to be considered.

Response

The Turk unit will be equipped with a low SO_2 to SO_3 conversion catalyst.

Catalyst washing, according to SWEPCO, is in development and not commercially available. AEP is in a "joint development initiative" with SCR Tech, LLC to develop the technology.

Other additives, according to SWEPCO will not significantly affect SO_3 rates due to the low SO_3 in the flue gas (August 15, 2008 Second Supplemental Response to

Comments on ADEQ's Draft Air Operating Permit for the John W Turk, Jr. Power Plant).

Reviewing the chart provided by the commenter reveals that most of the PC boilers using PRB are in the 0.004 lb/MMBtu and above range. The units with lower emission rates are smaller units; Desert Rock is incorrectly listed as 0.002, where as the permit states 0.004 lbs/MMBtu. The operational status of the permits listed is not mentioned by the commenter.

Both commenter and applicant cite issues with testing for SAM and the commenter even mentions a vendor unwillingness to provide guarantees below a 0.006 lb/MMBtu equivalent.

SWEPCO has proposed a new limit of 0.0042 lbs/MMBtu as BACT to coincide with the lowest permitted similar source, after evaluating the chart provided by the commenter. Refer to comment VI, and Figure 5 of July 31, 2007, Comments on Draft Operating Air Permit No. 2123-AOP-RO, John W. Turk, Jr., Power Plant (AFIN: 29-00506), for Southwest Electric Power Company (SWEPCO) submitted by Frederick W. Addison, III,
Munsch Hardt Kopf & Harr, P.C..

34. BACT is not achieved for lead emissions from PC boilers. The draft permit sets a BACT emission limit for lead of 0.000026 lb/MMBtu based on a 3-hour average to be achieved with the baghouse. However, the application does not explain why three lower lead limits found in its RBLC search -- 0.0000169 lb/MMBtu for Santee Cooper, 0.0000256 for Springfield, and 0.0000113 for Nevco Sevier -- do not constitute BACT for this facility. The BACT analysis calculated the lead BACT emission level from a generic, industry-wide average emission factor in AP-42. The assumption that BACT for PM satisfies BACT for lead is not correct. The commenter identified other BACT limits even lower that must be considered.

    A BACT analysis for lead must consider methods to enhance the removal of these finer particles. Methods to enhance the control of fine lead particles include: (1) use of a filtration media with a higher removal efficiency for nanoparticles; (2) use of a wet electrostatic precipitator (Ex. 125); and (3) use of an agglomerator upstream of the baghouse. An agglomerator uses electrical charges to attach nanoparticles to larger particles, which are then more efficiently removed by the baghouse. Agglomerators have been used to reduce opacity (caused by nanoparticles) and PM at several coal fired power plants.

Response

The three referenced lower limits were originally discounted because of differences in processes or insignificant differences in emission limits. The Springfield limit is 0.0000256 lb/MMBtu as opposed to 0.000026 lb/MMBtu for SWEPCO. Nevco Sevier and Santee Coooper are CFB boilers, a fundamantally different design.

The commenter failed to consider averaging times in the other units cited. Review of the available files revealed quarterly and annual averages. Longer averages equate to higher limits.

As part of the 112(g) permit, SWEPCO has proposed a revised emission rate of 0.000016 lbs/MMBtu, 3 hour average. This is below all the limits for those units identified by the commenter that do not have extended averaging times.

In their August 15, 2008 Second Supplemental Response to Comments on ADEQ's Draft Air Operating Permit for the John W Turk, Jr. Power Plant, SWEPCO addressed the issue of advance filter media and agglomerators. The advanced filter media is in the early stages of research. Agglomerators are a retrofit technology for ESP systems. No information has ever been presented that agglomerators would improve the performance of new properly operating systems.

The commenters reference for a wet ESP provides no useful information in comparing a wet ESP performance to a fabric filter.

35. A BACT limit was not established for fluoride emissions from the PC boiler. "Fluorides" are organic and inorganic compounds containing the element fluorine. This class of compounds is regulated under the PSD program. If emissions of "fluorides" from a source exceed 3 ton/yr, they are "significant." 40 CFR 52.21(b)(23). A BACT analysis must be conducted if emissions exceed the significance threshold.

Response

Fluoride emissions do not exceed the 3 ton per year threshold. Fluorides emitted are in the form of HF which is not regulated by the PSD rules, but rather by MACT rules.

36. BACT is not achieved for startup and shutdown emissions from the PC boiler. The draft permit provisions regarding startup, shutdown, maintenance and malfunction are vague, and should be clarified.

Response

The proposed BACT limit has been lowered to 0.08 lb/MMBtu SO_2 30-day average emission limit with a 480 lbs/hr 24 hour limit. Both the 480 lb/hr limit and the 0.08 lb/MMBtu limit apply to all times. For NOx, a daily limit of 420 lbs is incorporated for all times and a lb/MMBtu limit will apply at all normal operations. For purposes of this requirement normal operation is defined as 300 MW gross output from the Unit 1 generator.

Other than NSPS exemptions which the Department cannot effect, there are no other start up or shut down provisions.

37. BACT is not achieved for opacity from any source. BACT for opacity should be 5% for the PC boiler.

Response

A BACT analysis is not required for opacity. Opacity is not a regulated pollutant. Rather, the permit limits that represent BACT for the chosen technology will be incorporated into the permit. The main boiler will have a 10% opacity limit with a 27% short term allowance similar to the NSPS. The draft permit contains opacity limits for other sources as appropriate. The commenter has made no specific statement about these limits contained in the draft permit.

38. BACT is not achieved for PM emissions from the cooling tower. The BACT limit for PM/PM_{10} emissions from the cooling tower as 0.001% drift eliminators is unsubstantiated. Also, the draft permit conditions do not identify the 0.001% drift eliminators and corresponding PM/PM_{10} emission rates, as BACT limits. The proposed drift efficiency is not BACT. A 0.001% drift eliminator is not BACT for the new cooling tower. Much higher efficiency drift eliminators, typically 0.0005% drift efficiency, are widely used on coal fired power plants. These include: Prairie State, IL; Rocky Mountain Power Hardin, MT; Longview, WV; Intermountain, UT; Newmont, NV; Comanche Generating Station, CO; Desert Rock, NM; Weston 4, WI; and Indeck-Elwood, IL.

Response

The Department agrees. The final permit and limits will contain a 0.0005 % drift efficiency requirement and emission rates derived from that specification.

39. Alternative (dry) cooling technologies were not considered. The adverse impacts of a wet tower need to be considered; dry cooling will eliminate these impacts.

Response

- **The commenter did not provide any examples of coal fired power plants using a dry cooling technology. In information provided in an August 15, 2008 Second Supplemental Response to Comments, SWEPCO asserts that dry cooling is not a practical alternative for the Turk plant because of design and economic considerations. Specifics cited by SWEPCO are:**
  - **System Size: Dry cooling systems cool with air instead of water, and are much less efficient than water cooled systems. To achieve a comparable heat rejection, dry cooling systems must be of a larger design. For the same cooling capacity, an air cooled condenser will have a footprint that is approximately 2.2 times larger and nearly**

twice as tall as a wet cooling tower. *See* Wayne C. Micheletti & John M. Burns, P.E., *Emerging Issues and Needs in Power Plant Cooling Systems* (Exh. 7 to SWEPCO's Nov. 15, 2007 comment responses). This additional size also results in additional capital cost associated with the dry cooling system.

- **Energy Penalty: Dry cooling efficiency decreases with higher ambient temperatures. At ambient air temperatures above 90° F, effective cooling becomes increasingly more difficult and can reduce plant output on days of greatest electric demand. (Exhibit 8). Because the location of Turk facility has a summer design dry bulb temperature of 109° F or more, a dry cooling system is not the most cost-effective or efficient cooling option.**

- **Operation and Control: Ambient air temperatures vary during the course of a day on average by 15° to 25° F, as opposed to river water temperatures that are fairly constant and change more gradually over time. As a result, the operation of a dry cooling system requires additional control equipment to maintain unit efficiency and performance. To minimize the impacts of ambient temperature fluctuations, increased surface area is added to the air cooled condenser, which further increases the size and costs.**

- **Maintenance: The dry cooling system will increase the cost and frequency of maintenance in order to address the larger, more complex system.**

- **Auxiliary Power: The quantity of fans associated with a dry cooling system results in a greater auxiliary power demand than for a wet cooling system. Additionally, the larger equipment footprint associated with a dry cooling system requires more lighting and other plant utilities to support safe and efficient operations.**

In addition, SWEPCO states in regards to water flow issues:

> **In order to maintain the minimum flow to protect fish and wildlife resources downstream of the Turk plant, SWEPCO has agreed to contract with the Southwest Arkansas Water District ("SAWD") for 11,200 acre-ft of Millwood Lake storage. The SAWD will deliver water to the Turk plant by causing releases from SWEPCO's allocated storage space in Millwood Lake to the Little River.**
>
> **The Arkansas Game and Fish Commission ("AGFC") expressed a similar concern in a January 25, 2007 letter to SWEPCO's counsel. APSC Docket 06-154-U. Based on SWEPCO's above commitment to augment releases to**

the Little River during low-flow periods to maintain the minimum flow necessary to protect fish and wildlife resources, the AGFC issued a letter on May 24, 2007 stating that their concerns have been adequately addressed. APSC Docket 06-154-U.

Wet cooling towers are common and ADEQ is not aware of any issues regarding Legionnaires disease. Common practices in cooling tower operations include use of chemicals to prevent such issues from arising.

Any discharges from the wet cooling system will be required to comply with all applicable laws and regulations. Such discharges will not have adverse impacts.

40. The Turk plant is subject to the BACT requirements of 42 U.S.C. § 7475(a)(4). Rather than make a full and objective BACT determination, SWEPCO proposed emission limits that are less stringent than BACT. Once an emission unit is subject to BACT, the PSD program does not allow the imposition of an emission limit that is less stringent than that required by BACT. SWEPCO's continuing efforts to permit the Turk plant at emission limits less stringent than required by BACT constitute continuing violations of 42 U.S.C. § 7475(a)(4).

Response

ADEQ has evaluated emission limits and has determined that the limits that are established in the final permit are representative of BACT.

Alternative Fuels

41. There has been and continues to be a failure to analyze fully and determine objectively whether alternative fuel sources would achieve lower NOX, SOX, PM, and mercury emissions than PRB coal at the Turk plant. Such failure constitutes continuing violations of 42 U.S.C. § 7475(a)(4). There has been and continues to be a failure to use alternative fuel sources to PRB to accomplish BACT at the Turk plant. Such failure constitutes continuing violations of 42 U.S.C. § 7475(a)(4).

"[E]energy environmental and economic impacts and other costs" are required to be analyzed and taken into account when determining the benefit of alternative fuel sources alternative fuel costs at in a proper BACT analysis. There has been and continues to be a failure to do so regarding the Turk plant. Such failure constitutes continuing violations of 42 U.S.C. § 7475(a)(4).

ADEQ did not consider clean fuels when setting the SO_2 (or any other limit such as NOX and PM) in the draft permit.

Response

Alternative/Clean Fuels are addressed in other comments and responses.

42. A proper, common and sufficient BACT analysis for the Turk plant requires that any other AEP/SWEPCO facilities whose emissions or reductions are proposed to offset new emissions from the Turk plant must themselves be BACT compliant.

Response

The commenter fails to cite any relevant regulatory requirement in this statement. In any event, no emissions are proposed to be offset in this permit. Visibility impacts are proposed to be offset by reductions at the SWEPCO Welsh plant but these are not BACT requirements or limits. Welsh is not otherwise required to make these emission reductions.

Design Parameter Analysis

46. A proper BACT analysis requires, among other things, the provision of design parameters for the control technology reviewed. The BACT analysis for the Turk plant does not include sufficient design parameter information for SCR or the proposed dry flue desulferization system. Design parameters needed for the BACT analysis of SCR include, inter alia, space velocity, ammonia to NOX molar ration, pressure drop, and catalyst life. Design parameters needed for the BACT analysis of carbon injection systems include, among other technologies, injection concentration of the sorbent measured in lb/MMacf, expected flue gas conditions (including temperature and concentrations of, HCl and SO_3,) the air pollution control configuration, the characteristics of the sorbent, and the method of injecting the sorbent). The omission of this information from the BACT analysis results in a flawed BACT determination and constitutes continuing violations of 42 U.S.C. § 747(a)(4).

Response:

Where necessary, design information was included. This includes basics of boiler sizes, material usages, and some design considerations. These design considerations were used in among other things, emission rate calculations, cost estimates, and air quality analysis.

There is no value in requiring design information for which there is no use.

Incremental Costs Analysis

47. When considering economic factors in a BACT analysis, incremental cost effectiveness between control options should be used. Instead of using incremental cost effectiveness, the BACT analysis performed for the Turk plant, SWEPCO determined BACT according to which control technology was less expensive in itself. The use of cost instead of incremental cost effectiveness and other proper economic reasonableness factors in the BACT analysis results in continuing violations of 42 U.S.C. § 7475(a)(4).

Response

The comment refers to SO_2 emissions and controls.

Incremental costs were provided in a July 30, 2007 supplement. In it, SWEPCO lists the incremental costs for wet FGD to be $21,360/ton based on a 0.10 lb/MMBtu emission rate. Incremental costs would be higher based on the revised 0.08 lb/MMBtu emission rate.

Air Quality Analysis Issues

48. Modeling is deficient and on-going.

Response

At the time of the draft permit issuance, no modeling was ongoing. All results were presented in the draft permit in the air quality analysis.

In response to comments and issues raised, additional modeling was conducted. This additional modeling is discussed individually in other responses contained in this document. In brief, this modeling included:

- **Modeling with the latest approved version of Calpuff, this did not change any predicted results**
- **Incorporating a lower SO_2 emission rate**
- **Modeling with an updated SO_2 Emission inventory**
- **Modeling for visibility to mitigate impacts by reductions at the SWEPCO Welsh plant**
- **Revised Class II models to account for final road design and the addition of several inventory sources.**

All this modeling was conducted as a result of comments. No substantial changes to any impacts were predicted that would have changed the original draft permit decisions.

49. ADEQ failed to adequately conduct the required full impacts analysis to determine whether this proposed source would cause or contribute to a violation of the national health-based ambient air quality standards (the "NAAQS") or PSD increments (including visibility in a Class I area). A full impact analysis was performed only for PM_{10}. However, SWEPCO's own modeling indicates that a full impacts analysis is also required for SO_2, and possibly for NOx as well.

Response:

A full impact analysis was only required for PM_{10} and a Class I increment analysis for PM_{10} and SO_2. A full impact (NAAQS) analysis for SO_2 and NOx was not

required based on the significance analysis. This is documented in the Class II analysis contained in the application. The modeling does not support the need for a full impact analysis for pollutants other than PM_{10}.

Visibility impacts are not conducted in the same manner as other pollutants and thus do not have screening or full impact analysis. Visibility impacts were clearly laid out in the Class I analysis. Visibility issues were resolved in a July 22, 2008 letter from Norm Wagoner, Forest Supervisor, these comments concerning adverse impacts were withdrawn based on mitigation measures and permit language proposed by SWEPCO.

50. SWEPCO uses inappropriate methods for air dispersion modeling of fugitive dust emission sources. The comment specifically addressed roads as volume sources and the release height used in the model.

Response

Arkansas typically models road emissions as volume sources, dispersing in three dimensions as opposed to area sources dispersing in two. There is no stated EPA method on how to model such emissions, but other states follow procedures similar to those used by Arkansas. This is not an "unorthodox" procedure as stated by the commenter. From the page 3-17 of the USER'S GUIDE FOR THE AMS/EPA REGULATORY MODEL – AERMOD EPA, EPA-454/B-03-001, September 2004:

> **Certain types of line sources can be handled in AERMOD using either a string of volume sources, or as an elongated area source. The volume source algorithms are most applicable to line sources with some initial plume depth, such as conveyor belts and rail lines. Section 1.2.2 of the ISC Model User's Guide - Volume II (EPA, 1995) provides technical information on how to model a line source with multiple volume sources. The use of the AERMOD area source algorithm for elongated rectangles would be most applicable to near ground level line sources, such as a viaduct.**

From 40 CFR Part 51, Appendix W Sections 5.2.2.2 and 8.1.1

> **Fugitive dust usually refers to dust put into the atmosphere by the wind blowing over plowed fields, dirt roads or desert or sandy areas with little or no vegetation. Reentrained dust is that which is put into the air by reason of vehicles driving over dirt roads (or dirty roads) and dusty areas. Such sources can be characterized as line, area or volume sources. Emission rates may be based on site specific data or values from the general literature. Fugitive emissions include the emissions resulting from the industrial process that are not captured and vented through a stack but may be released from various locations within the complex. In some unique cases a model developed specifically for the situation may be needed. Due to the difficult nature of characterizing and modeling fugitive dust and fugitive emissions, it**

is recommended that the proposed procedure be cleared by the Regional Office for each specific situation before the modeling exercise is begun.

The line sources most frequently considered are roadways and streets along which there are well-defined movements of motor vehicles, but they may be lines of roof vents or stacks such as in aluminum refineries. Area and volume sources are often collections of a multitude of minor sources with individually small emissions that are impractical to consider as separate point or line sources. Large area sources are typically treated as a grid network of square areas, with pollutant emissions distributed uniformly within each grid square.

SWEPCO submitted revised modeling to incorporate finer detail on actual road location. ADEQ also modeled with the 1 meter release height commented on. None of this modeling resulted in any appreciable differences or differences that would affect any permit decision.

51. Class II impact modeling files were not provided to ADEQ until after permit issuance; therefore, ADEQ could not have conducted a detailed analysis.

Response

As a result of this comment, comments on fugitive emissions and inventory sources, SWEPCO and ADEQ have conducted supplemental Class II modeling and found no issues that would change the results presented in the application.

All meteorological data and parameters were found to be consistent with that stated in the application. Upon review of the list of sources included in the model, it was discovered that sources located in Texas were omitted from the NAAQS and Class II increment analysis. Thereafter, the analysis was reevaluated with the omitted sources and there were no changes in the predicted impacts.

52. The Shreveport, LA, airport meteorological data are unacceptable for Class II air dispersion modeling

Response

While it is true that the document referenced in the comment states concerns over airport data use, it also states on page 6-30 that:

Although data meeting this guidance are preferred, airport data continue to be acceptable for use in modeling. In fact observations of cloud cover and ceiling, data which traditionally have been provided by manual observation, are only available routinely in airport data; both of these variables are needed to calculate stability class using Turner's method (Section 6.4.1). The Guideline on Air Quality Models

recommends that modeling applications employing airport data be based on consecutive years of data from the most recent, readily available 5-year period.

5 years of data was used in the Class II modeling. Predicted impacts do not warrant additional site specific meteorological data.

53. Preconstruction meteorological monitoring should have been required. The State of Nevada guidelines require such monitoring.

Response:

All facility impacts were below significant impact levels except for PM_{10}. Even refined modeling for PM_{10} (using existing monitoring data) resulted in total impacts of, at most, 50% of the NAAQS and less for the increment.

Because of the low predicted PM_{10} impacts and other impacts below the significant impact levels, the requirement for pre-construction monitoring is not necessary.

The determination of pre-construction monitoring is site specific and determinations in other states are not necessarily applicable to this site.

54. SWEPCO's application provides no documentation for the Shreveport meteorological data and the data used is incorrect. The station ID in the application is incorrect.

Response

The correct station ID for Shreveport is 13957. This is the station data used in Class II modeling performed by the applicant and is identified as such in the meteorological data files. The reference to station 13893 in the permit is a typographical error.

ADEQ has compared the Class II modeling for the facility with result using data obtained directly from the National Weather Service and processed by ADEQ and found no differences of note.

ADEQ does not find any issues with the meteorological data used.

55. SWEPCO engaged in blatant "data-shopping:" and ADEQ neither challenged nor scrutinized this practice with respect to Class II meteorological data and analysis of visibility impacts

Response

ADEQ has evaluated and agreed to the use of Shreveport data; there was no "data shopping" involved in its selection. ADEQ typically uses Shreveport data for the area in which the plant will be located.

There is no reference to the tabulated list that the commenter references. Assuming the commenter is referring to the Tables in 4-8, 4-9 or 4-10 and discussions of the January 2007 Class I Area Modeling Assessment and Modeling Results, these tables do not manipulate or "shop" any data. Rather the tables present the results of the use of different dispersion modeling options or in one case evaluating weather conditions on a particular day to confirm the source of the visibility impact and discount the Turk facility as the contributor to visibility impairment.

The different modeling options listed include Method 6 that has been used by states in regional haze modeling and Method 8 that has been recommended in the recently proposed *FLAG Phase I Report—REVISED* and has been accepted in other PSD modeling.

The applicant is actually provided more and clearer data on the visibility analysis by tabulating all results based on different modeling options.

56. ADEQ should require an equitable analysis of weather events for visibility impairment when extinction coefficients are between two and five percent

Response

It is unclear what would be evaluated in such a case, what an alternative analysis consist of or how the two to five percent range is derived.

If the total impacts are acceptable, there is no reason to further evaluate components of the impacts.

57. Class I modeling must use regulatory-approved CALPUFF version and options. The applicant should conduct the modeling using the EPA-approved version of CALPUFF and submit the results for further review and comment.

Response

In September, 2007 SWEPCO submitted a supplemental Class I analysis to use the most current approved versions of the CALPUFF system, as issued by EPA on June 29, 2007. The supplement also included a revised SO_2 emission rate of 0.08 lbs/MMBtu, a reduction from the draft permit rate of 0.10 lbs/MMBtu. All predicted impacts decreased in this analysis.

It should be noted that the applicant also submitted a revised modeling analysis for Class I SO_2 impacts in May of 2008 in order to address concerns over potentially

omitted significant contributing sources. This analysis did not substantially change the results and is discussed in further comments.

58. ADEQ should verify the complete inventory of PSD-consuming sources. Emissions inventory used for PSD increment modeling analyses is flawed and does not accurately reflect increment consuming sources. Some of the newest PSDs that have been issued are not reflected in the increment inventory. Please verify and update the sources and emission rates that should be included in the Class I increment, visibility and NAAQS modeling. PSD permits in northwest Louisiana should be included in any increment/visibility consuming inventory. In particular, it appears that the Applicant and ADEQ have failed to consider PSD permits issued or pending for construction or modifications at pulp and paper facilities in northwest Louisiana

Response:

Based on this comment and comments from EPA, Region 6, the issue of Class I SO_2 impacts were re-assessed in a May 2008 Addendum to the SWEPCO Proposed John W. Turk Jr. Power Project Supplemental Class I Area Increment Modeling Analysis.

Additional minor sources in Arkansas were added as a result of this and a re-evaluation of the minor source baseline date was conducted. There were no significant changes to the results.

The inventory used for Louisiana was obtained from the state environmental agency. The commenter did not provide the name of the pulp and paper facility(s) that should be considered.

The comment noted that the inventory for an Oklahoma project was different than SWEPCO's inventory. ADEQ commented to Oklahoma that their inventory contained sources that were already included in the baseline emissions. Inclusion of a baseline source in the increment inventory would bias results to predict higher impacts and not compromise the final decision.

SWEPCO properly accounted for baseline sources in their inventory.

59. The Class I impact modeling uses an inappropriate CALPUFF puff splitting option.

Response

The FLM and EPA approved modeling for visibility and increment and found no issues with any of the modeling parameters used.

ADEQ's evaluation of results included increment analysis using Calpuff without puff splitting options and found no changes to the results.

The use of puff splitting is not specifically prohibited as a non-regulatory option according to the IWAQM document cited by the commenter.

60. Modeled SO_2 and NOx Emission Rates for NAAQS analysis are incorrect

Response:

The comment refers to the SO_2 emission rate in full impact modeling files sent to the commenter. These files were transmitted to ADEQ in error with other files and are not included in the analysis. A full impact analysis for SO_2 is not required.

61. Air quality impacts from reasonably foreseeable boiler startup, shutdown, and maintenance SO_2 emissions should be assessed. Start up and shut down limits and/or other exemptions or alternative emission limits for particulate matter and mercury during reasonably foreseeable startup, shutdown, or maintenance activities must be included in the modeling analyses for the Turk plant.

Response

The revised 24 hour SO_2 emission limit of 0.08 lbs/MMBtu is inclusive of start up and shut down. The revised 24 hour NOx emission limit of 0.067 lbs/MMBtu includes a 24 hour limit of 420 lbs per hour applicable at all times. Both these emission rates are appropriately modeled in the permit application. No other allowances for start up and shut down are contained in the permit with the exception of the NSPS and those are superseded by these BACT limits.

Visibility

62. SWEPCO's modeled background ammonia levels are questionable (0.5 ppb)

Response

The 0.5 ppb is an appropriate value for the Arkansas Class I areas which are forests.

From the INTERAGENCY WORKGROUP ON AIR QUALITY MODELING (IWAQM) PHASE 2 SUMMARY REPORT AND RECOMMENDATIONS FOR MODELING LONG RANGE TRANSPORT IMPACTS, EPA-454/R-98-019, December 1998, Page 14:

> **The ambient ammonia concentration is an input to the model. Accurate specification of this parameter is critical to the accurate estimation of particulate nitrate concentrations. Based on a review of available data, Langford et al. (1992) suggest that typical (within a factor of 2) background**

values of ammonia are: 10 ppb for grasslands, 0.5 ppb for forest, and 1 ppb for arid lands at 20°C.

In questioning this value, the commenter is presumably referencing a discussion of using ammonia levels based on a weighted value of the area between the source and the impacted area. There is no precedence or guidance for such a change to accepted modeling procedures.

63. The EPA recommends that ADEQ determine and document whether an assessment of the near-field plume visibility impacts is needed to satisfy the requirements for an "additional impacts analysis" under 40 CFR 52.21(o).

Response:

This analysis was included in the permit application under section 7.4.3 on page 7-37. The assessment showed that the Level I visibility analysis results were below the standardized screening criteria and thus are acceptable. No further analysis is required.

64. The Applicant did not perform adequate (Class I) visibility analysis/There will be an adverse impact on Class I visibility at Caney Creek and Upper Buffalo. Table 4-7 indicates that the 5% Light Extinction Threshold was exceeded on 35 days over the three year period modeled. This is not acceptable and must be mitigated. The current modeling assessment of Class I visibility estimates the proposed facility's impact exceeds 5% extinction change analysis. Consequently, the FLM has requested mitigation of the project's emissions that impact visibility impairment to avoid adverse impacts on visibility. Please work with the FLM to ensure that the proposed source's emissions will not have an adverse impact on Class I visibility (AQRV). These adverse impacts to visibility are in violation of the Clean Air Act and cannot support issuance of a PSD permit.

Response

Visibility impacts were clearly laid out in the Class I analysis submitted and summarized in the draft permit. This analysis contained visibility impacts as obtained using Calpost Method 2 procedures as well as other commonly used procedures. Based on comments received, including those of the Federal Land Manager (FLM), SWEPCO performed additional modeling to mitigate predicted visibility impacts as determined by the Method 2 results in the original modeling.

This additional modeling calculated visibility impacts of the SWEPCO Welsh plant before and after a proposed reduction in SO_2 emissions. Reductions sufficient to mitigate the impact of the proposed Turk plant were established in this modeling.

The FLM in a July 22, 2008 letter from Norm Wagoner, Forest Supervisor, agreed that based on the proposed mitigation measures, the proposed Turk plant would not

have an adverse impact on the Class I area. Specific conditions relating to these reductions are included in the final Turk permit.

65. In the Class I visibility analysis, Tables 4-8 through 4-10 include results using other settings that are not EPA's recommended settings. Please explain how any deviation from Appendix W recommendations for general modeling procedures or IWAQM Phase 2 settings have been justified in accordance with 40 CFR, Part 51, Appendix W, Section 3.2, which outlines the requirements necessary to justify and approve non-guideline models and alternative techniques.

Response:

The tables 4-8 through 4-10 include different dispersion options when evaluating visibility impacts only. These different options have been accepted at various times by other agencies in making visibility impact determinations. However, in making a determination of no adverse impacts from Turk, the FLM relied only on the approved Appendix W and IWAQM procedures.

66. Modeling conducted by Trinity Consultants and provided to ADEQ shows that the proposed plant will adversely impact visibility in the Caney Creek Wilderness Area. These results were then "tweaked" until the applicant got the "results they wanted".

Response

Class I analysis for the application was submitted by TRC on behalf of SWEPCO, not Trinity Consultants. In their analysis, TRC admittedly used various modeling techniques to predict Class I visibility impacts; all of which were clearly disclosed in the modeling analysis. Such refinements to modeling analysis are not prohibited and have been used in other permit evaluations in Arkansas and in other states. These refinements and references are discussed starting on page 4-12 of the January 2007 Class I Area Modeling Assessment and Results as well as in the September 2007 supplement.

Increment

67. If SO_2 emissions resulting from a properly performed BACT analysis can be shown to cause or contribute to violations of the NAAQS or increments or would result in adverse impacts on AQRV's, then a lower rate will need to be considered.

> The increment analysis indicates numerous exceedences of the 3 hour SO_2 Class I increment have been estimated, rather than calculated. If estimates are to be used, they must be verified in order to determine that the Turk facility's emissions do not cause or contribute to any modeling violation. The revised modeling however should be performed only with PG dispersion setting as set forth in the 1998 IWAQM Phase II Report and the Federal Land Manager's Air Quality Related Values Workshop (FLAG) Phase I Report (December 2000).

Response

The applicable requirement is found in 40 CFR 52.21 (k):

> **(k) Source impact analysis. The owner or operator of the proposed source or modification shall demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), would not cause or contribute to air pollution in violation of:**
> **(1) Any national ambient air quality standard in any air quality control region; or**
> **(2) Any applicable maximum allowable increase over the baseline concentration in any area.**

In this case, cause or contribute is determined by comparison with the Class I Significant Impact Level for those times that the increment is predicted to be exceeded. For such analysis, the highest second high impacts are used in accordance with Appendix W. This approach is further discussed in the July 5, 1988 EPA Memorandum titled Air Quality Analysis for Prevention of Significant Deterioration (PSD) from Gerald A. Emison, Director, Office of Air Quality Planning and Standards (MD-10).

That memorandum described the preferred approach on how to interpret dispersion modeling results to determine whether a source will cause or contribute to a new or existing violation of a NAAQS or PSD increment. The preferred approach project air quality concentrations throughout the proposed source' impact area, but does not automatically assume that the proposed source would cause or contribute to a predicted NAAQS or increment violation. Instead, a further step is required in the event that a modeled violation is predicted.

> **The additional step determines whether the emissions from the proposed source will have a significant ambient impact at the point of the modeled NAAQS or increment violation when the violation is predicted to occur. If it can be demonstrated that the proposed source's impact is not "significant" in a spatial and temporal sense, then the source may receive a PSD permit.**

***Id.* By following this approach, there are three possible outcomes:**

> **(1) [D]isperson modeling may show that no violation of a NAAQS or PSD increment will occur in the impact area of the proposed source. In this case, a permit may be issued and no further action is required.**
> **Or**

(2) [A] modeled violation of a NAAQS or PSD increment may be predicted within the impact area, but, upon further analysis, it is determined that the proposed source will not have a significant impact (i.e., will not be above de minimus levels) at the point and time of the modeled violation. When this occurs, the proposed source may be issued a permit (even when a new violation would result from its insignificant impact), but the State must also take the appropriate steps to substantiate the NAAQS or increment violation and begin to correct it through the State implementation plan (SIP).

Or

(3) [T]he analysis may predict that a NAAQS or increment violation will occur in the impact area and that the proposed source will have a significant impact on the violation. Accordingly, the proposed is considered to cause, or contribute to, the violation and cannot be issued a permit without further control or offsets.

***Id.* In this case, the second outcome discussed above occurred. A PSD increment violation was modeled, but upon further analysis it was determined that the impact was not above the de minimus level and, therefore, not significant.**

The highest second high impact of Turk on any 24 hour period of predicted increment exceedence (i.e. above 5 $\mu g/m^3$) is 0.19 $\mu g/m^3$ which is below the SIL of 0.2. For the 3 hour period, the contribution of Turk is never over 0.006297 $\mu g/m^3$ during any predicted increment exceedence (above 25 $\mu g/m^3$); this is below the SIL of 1.0 $\mu g/m^3$. Thus, the proposed source's emissions do not significantly cause or contribute to any modeled violations of the 3-hr or 24-hr SO_2 Class I increment.

This modeling analysis is contained in the May 2008 Class I supplement and uses the referenced PG dispersion methods.

68. Prior to obtaining its permit from ADEQ, SWEPCO is required to perform a cumulative impacts analysis that demonstrates allowable emissions increases from the Turk plant in conjunction with all other applicable emissions increases or reductions (including secondary emissions from other sources). The required cumulative impacts analysis also must demonstrate that emissions increases at the Turk plant and other facilities will not cause or contribute to air pollution in violation of any NAAQS or any applicable maximum allowable increase over baseline concentrations in any area. SWEPCO failed to perform a cumulative impacts analysis that makes these demonstrations.

Response

All required Class I and Class II analyses were conducted and documented in the application. There has been no failure to conduct any air quality analysis.

69. SWEPCO has failed to determine that increases in NOx, mercury, SO_2, $PM_{2.5}$, PM_{10}, CO_2, and ozone resulting from the Turk plant, in conjunction with all other applicable emissions increases, will not cause or contribute to air pollution in violation of NAAQS, applicable maximum allowable increases over baseline concentrations, national ambient air quality standards or any other applicable emissions standard or standard of performance. This failure constitutes continuing violations of 42 U.S.C. § 7475(a)(3) and 40 C.F.R. § 52.21(k).

Response

$PM_{2.5}$ New Source Regulations are not yet implemented by the state of Arkansas. As an "approved" state, the state has 3 years from the date of the rule to incorporate the provisions into its regulations. In the interim and in accordance with EPA policy, PM_{10} remains the regulated pollutant.

NOx, SO_2 and PM_{10} have been appropriately modeled to show compliance with all NAAQS and increments.

CO_2 is not a regulated pollutant for which an air quality or other analysis is required.

Mercury has no National Ambient Air Quality Standards (NAAQS), air quality standard or other standards. An air quality screening analysis was conducted for mercury and all other non criteria pollutants in accordance with the Department's Non Criteria Air Pollution Control Strategy. In addition, mercury impacts were evaluated in a report to the Arkansas Public Service Commission titled John W. Turk, Jr. Power Plant TRC Discussion of Mercury Emissions, Deposition, and Human Health Risk Analyses Stemming from Arkansas PSC Hearing – Docket 06-154-U February 2008. ADEQ has reviewed this report and has no issues with its conclusion that mercury will not create an adverse impact. It should be noted that this report was based on mercury emission levels before further reductions were proposed as part of the 112(g) permit application.

70. SWEPCO has failed to evaluate completely or correctly the impacts on ozone by NOx emitted from the Turk plant. This failure constitutes a continuing violation of 42 U.S.C. § 7475(a)(6).

Response

Ozone modeling is a regional air shed model that encompasses emissions over a large geographic area. The models do not predict the impact of any one source.

In the regulation of ozone, agencies do not evaluate source by source impacts in a permit program as they do with other pollutants. When ozone issues (non-attainment) arise in an area, agencies will develop strategies and rules based on among other things, air shed modeling. The area around the Turk plant is in

attainment for ozone. Any future planning will incorporate the emissions from the plant to establish such strategies.

Emission rates

71. The Turk plant's projected short-term and annual emissions do not take into account start-up, shut-down, maintenance, and malfunctions, which are required to be considered when determining the projected actual emissions for purposes of PSD (i.e. before beginning actual construction).

Response

The comment references 52.21(b)(41)(ii) which is a section that pertains to modifications at existing units. The comment is not relevant to a permit for a new plant.

72. The emission summary (draft permit p. 20) should be altered to reflect a higher ton per year limit for PM. Based on 195.3 lb/hr, the annual PM emission rate is 855 tons/year. Any modeling or other determination based on this erroneous calculation should be re-done.

Response

Presumably, the PM comment refers to PM_{10} since PM is not a modeled emission. Not all sources in the permit are permitted to operate continuously, thus the lower annual emission rates compared to a short term rate operating continuously (i.e. 8760 hours per year). In any event, it is the higher hourly emission rate that was modeled. Any determination based on the annual emission rate correctly used the lower value.

73. SWEPCO's assumption of 90% control for unpaved road dust is overly optimistic and values used to calculate this efficiency were not contained in the application.

Response:

SWEPCO has, in a September 3, 2008 letter, provided the parameters used in the calculation contained in Control of Open Fugitive Dust Sources. Based on these values, a 90% control efficiency is calculated in the equation.

In addition and based on these parameters, SWEPCO has more clearly defined their unpaved road fugitive dust plan. The Specific Condition 62 of the permit has been revised to contain additional detail and states as follows

> **62. The permittee shall develop a haul road maintenance plan to clean or treat haul roads at this facility. This plan shall be designed to minimize emissions from this source. A copy of this plan shall be kept on site and**

made available to Department personnel upon request. At a minimum, the plan shall contain the elements listed in a - c below. [Regulation 18, §18.1004, Regulation 19, §19.705, 40 CFR 70.6 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

a. **At a minimum, the frequency of application of water or dust suppressant shall occur daily unless otherwise required as a result of inspections required by Specific Condition 62b.**

b. **Daily inspections of unpaved roadways shall occur to determine the needed frequencies of application of dust suppressant. If this daily inspection determines that the unpaved roadways are covered with snow and/or ice, or if precipitation has occurred that is sufficient for that day to ensure fugitive dust has been minimized, then the requirements of section a above shall not apply for that day.**

c. **The facility shall maintain records of these daily inspections including observed conditions and actions taken**

74. The controls proposed are not adequate and emissions are excessive compared to other plants.

Response

All controls and emission limits have been evaluated in accordance with applicable laws and regulations. The limits in the draft permit represent Best Available Control Technology (BACT) or Maximum Achievable Control Technology (MACT) as defined in regulations. The commenter makes no specific reference to an emission rate or other plant.

Coal Piles Emissions

75. The emissions associated with SWEPCO's coal piles have not been completely or accurately established; no BACT has been proposed or determined for these emissions sources, and emissions from SWEPCO's coal piles are not being reduced to the maximum extent possible as required by law.

Response

The comment, in part references information provided in the EIS. Contradictory information in the EIS need not be reconciled by the air permit. The air permit accurately establishes coal pile emissions. Coal pile emissions were included in all analysis including BACT (section 6-4 of the application).

Coal Volume Consumption Inconsistencies

76. It is impossible to determine from the myriad of inconsistent SWEPCO filings the amount of coal that will actually be used at the Turk facility. Issuance of this air permit without determining the actual amount of coal to be used at the Turk facility would be arbitrary, capricious and not in accordance with law.

Response

Coal use and throughputs are contained in the permit application. The commenter references amounts stated in the EIS as the basis for this comment. This air permit is not based on coal usage information in the EIS.

Potential to Emit Calculations

77. The annual "potential to emit" calculations regarding the Turk plant do not take into account, and there is no information concerning, Turk plant emissions from: (a) a start-up, shutdown or maintenance activity; or (b) a malfunction event. A proper BACT analysis requires consideration of such omitted emissions and their impact on emissions calculations. Without the omitted information, it is not possible to determine whether the Turk plant could or will comply with BACT emission limits.

> In addition to the violations described in the immediately preceding paragraph, the concomitant failure to demonstrate compliance with short-term and long-term emission limits during start-up, shutdown, maintenance, or malfunctions also constitutes continuing violations of 42 U.S.C. § 7475(a)(4) because, inter alia, it fails to demonstrate that the Turk plant is subject to BACT regarding the source and control and/or reduction of such emissions

Response

In establishing and agreeing to emission limits, SWEPCO included consideration of such events. In one case, where NO_x emission rates were lowered based on comments, SWEPCO added a secondary limit for times regardless of start up and shut down.

The remaining BACT limits in the permit apply at all times. Emissions in excess of that established in the permit are not allowed.

Enforceability

78. ADEQ must clarify that the permit, if issued, is subject to federal enforceability. The draft permit must be clarified so that it is not construed to place impermissible limits on federal enforceability. Specific Condition 2, and General Provisions 1 and 18 create this confusion.

> Specific Conditions 2, 24, and 32 reference Regulation 18 and state law as the sole source of authority for hourly and annual limits for a laundry list of toxic chemicals.

The emission sources covered by these permit conditions are subject to federal regulation, and some of the limits (e.g. mercury) are derived from federal new source performance standards or other federally-approved state standards.

Specific Condition 8 should be clarified to state that continuous emissions monitoring data may be used not only by ADEQ, but by anyone for enforcement purposes.

Response:

The permit is federally enforceable except for those items specifically indicated as state only requirements in the permit.

Arkansas operates a one permit system that includes all requirements of a source, whether they are derived from a federally enforceable program, such as Regulation 19, or a state only (Regulation 18) requirement. Not all conditions in an Arkansas permit issued under Regulation 26 are automatically federally enforceable.

Because the facility is subject to the requirements of 112(g) of the Clean Air Act, all hazardous air pollutant limits will be referenced as federally enforceable limits. Sulfuric acid will be added because it is a PSD regulated pollutant. Ammonia is not regulated by a federal program and will remain a state only enforceable limit.

No changes will be made to General Provisions 1 and 18 as they are correct in their language.

Nothing in Specific Condition 8 restricts its use to ADEQ alone so no changes will be made to the condition.

79. ADEQ should have made a determination of non-compliance under Regulation 8, Sec. 2.1.18, based on AEP/SWEPCO's poor environmental compliance record. ADEQ failed to conduct the required non-compliance determination. ADEQ failed to include in the draft permit a compliance plan, as required for all federal Operating Permits. ADEQ knew or should have known of SWEPCO's pending enforcement action in Texas.

Response:

Regulation 8:
Regulation 8, § 2.1.18(a) provides that the Director may deny an applicant's request for the issuance of any permit, upon a determination that the applicant has a history of non-compliance or a pattern of disregard for state or federal environmental laws or regulations. This determination is to be based upon information that is required to be submitted by the applicant, including any civil or criminal enforcement action taken against the applicant or affiliated persons in the last ten years, including administrative actions resulting in sanctions, pending actions, actions resulting in a settlement, and permit or license revocation or denial. Regulation 8, § 2.1.18(b)(4).

Regulation 8, § 2.1.18(d) authorizes the Director to deny a permit if the Director finds:

> **(1) The applicant has misrepresented or concealed any material fact in the application of disclosure statement, or in any other report or certification; or**
> **(2) The applicant has obtained or attempted to obtain the issuance or transfer of any permit, license, certification or operational authority by deliberate falsification or omission of relevant information from disclosure statements; or**
> **(3) The applicant has a documented continuing history of criminal convictions, based upon violations of state or federal laws or regulations; or**
> **(4) The applicant has a documented history of violations of state or federal environmental laws or regulations that evidence a history of non-compliance or a pattern of disregard for state or federal laws or regulations; and has either made no attempt or has failed to remediate the disclosed violation.**

APC&EC regulations require permit applicants to provide specific compliance information as part of any permit application. SWEPCO complied with these requirements. The commenter does not allege that SWEPCO failed to disclose or misrepresented any pertinent information, or that SWEPCO has obtained or attempted to obtain the issuance or transfer of any permit, license, certification or operational authority by deliberate falsification or omission of relevant information, or that SWEPCO has a documented continuing history of criminal convictions.

Commenters claim the Director should not issue a permit to SWEPCO due to environmental violations that occurred at a SWEPCO plant located in Texas. In that case, the Sierra Club alleged that SWEPCO violated certain provisions of Permit No. 4381/PSD-TX-3, including heat input, the sulfur content of fuel, opacity and particulate matter limitations.

This matter was resolved through the negotiation of a Joint Consent Decree that was approved by a federal court. The Consent Decree requires, among other things, SWEPCO to install and operate new continuous monitoring equipment for particulate matter on all three units at the Welsh Plant. These measures directly address the particulate matter and opacity claims alleged by the Plaintiffs. Further, the entry of this Decree resolved all claims that were made or could have been made regarding SWEPCO's action to the date of the entry of the Decree – June 16, 2008. As no allegation has been made that SWEPCO has violated the terms of the Texas Consent Decree, the Director has no basis to deny the issuance of the permit under the provisions of Regulation 8§ 2.1.18(d).

Commenters have not presented any evidence that SWEPCO is not in compliance with any existing consent orders. Therefore, such consent orders cannot under Regulation 8 be considered as a "history of non-compliance." Regulation 8, § 2.1.18(d)(4)(A)(iii).

Factors relevant to determining whether an applicant has engaged in a pattern of disregard for environmental regulations include: (1) the nature and substance of violations attributed to the applicant, (2) the degree of culpability, (3) history of violations, (4) whether the applicant has substantially complied with this state's and other states' laws, regulations, and orders (5) mitigation factors, (6) the best interests of the public, and (7) and other information that the Director may require from the applicant. Regulation 8, § 2.1.18(d)(4)(A)(i)—(viii).

The phrase "pattern of disregard" necessarily requires numerous violations. No bright-line rule exists. The number and seriousness of the violations are considered in relation to the size and complexity of the applicant's operations. The allegations raised in the comment do not rise to the level of a pattern of disregard for environmental laws.

Schedule of Compliance Comment Response:
40 C.F.R. § 70.5(c)(8)(iii)(C) requires all Part 70 sources to include a "schedule of compliance for sources that are not in compliance with all applicable requirements at the time of the permit issuance." ADEQ interprets this section to be source-specific rather than company-specific. Therefore, any pending enforcement actions in Texas and federal action involving new source review violations against other AEP and/or SWEPCO sources are not relevant to the source at issue here—the Turk power plant. Further, AEP/SWEPCO prevailed in the citizen suit case in federal court in Texarkana and is currently pending on appeal. The Turk power plant is not out of compliance. Therefore, a schedule of compliance pursuant to 40 C.F.R. § 70.5(c)(8)(C)(iii)(C) is not required.

80. Prior to the issuance of the permits for the John W. Turk, Jr. facility, SWEPCO had already awarded contracts to The Shaw Group of Baton Rough (sic), Louisiana (700 Million) to build the facility and to Babcock and Wilcox (250 million) for the design, supply and erection of a portion of the plant. The commenter asked if this is an indication that SWEPCO is assured of receiving the necessary permits from the regulatory agencies.

Response:

There are no assurances that a permit will be issued for any applications received by the Department. This permit was no exception.

81. Please consider the needs of birds and other wildlife in the Little River Bottoms by denying a permit to SWEPCO until SWEPCO either chooses an alternative site for the power plant or proves that plant operations won't harm this ecologically sensitive area.

Response:

Pursuant to ADEQ's air permitting authority, it is required to set emission limits for proposed facilities. Other state and federal agencies require a review of a proposed

coal-fired generating plant facility's impact on wildlife. Before the Arkansas Public Service Commission issued an Order granting SWEPCO a Certificate of Environmental Compatibility and Public Need to construct the Turk plant in Hempstead County, Arkansas, state agencies, including the Arkansas Game and Fish Commission were invited to comment.

Arkansas Game and Fish Commission filed a response on October 18, 2007. In their letter they concluded that the Environmental Impact Study (EIS) had addressed their concerns. Following a lengthy hearing on the application, the Public Service Commission also concluded that "the impact to the ecological sources on the plant property will me minor..., the impacts of physical activities on the plant property to area ecological resources, such as the Little River Bottoms, including Grassy Lake, will be insignificant, if not immeasurable...and duck mortality from striking transmission wires is minimal." See Order No. 11 at 52-53.

82. (SWEPCO's) air emissions are a threat to birds and wildlife.

Response:

The comments are all general in nature and do not reference any specific emission level as being detrimental or not in accordance with regulations. The effects of mercury were evaluated in the report to the Arkansas Public Service Commission (PSC), John W. Turk, Jr. Power Plant TRC Discussion of Mercury Emissions, Deposition, and Human Health Risk Analyses Stemming from Arkansas PSC Hearing – Docket 06-154-U, February 2008 the facility considered the impacts of mercury and concluded that any impacts would be acceptable. Since that time, the permit has been modified to provide for even lower mercury emissions rates. SWEPCO also committed to a mercury sampling program with the PSC. The ADEQ reviewed the information contained in the report and does not have any issues with the analysis.

83. SWEPCO has not provided any information regarding health costs associated with the emissions that will result based on the technology proposed for the Turk plant. A proper BACT analysis requires consideration of the energy, environmental, and economic impacts and other costs. 42 U.S.C. § 7479(3). By failing to consider health costs associated with the technology and emissions proposed for the Turk plant, the BACT analysis is defective and incomplete. The BACT analysis also is defective and incomplete because of the failure to compare health costs associated with the technology and emissions proposed for the Turk plant with health costs associated with alternative control technologies and related emissions calculations. Each of these failures constitutes continuing violations of 42 U.S.C. § 7475(a)(4).

Response:

There is no such regulatory requirement to consider health costs in this manner. NAAQS are designed to ensure public health. BACT is not required to evaluate

health costs in the stated manner of absolute health costs; rather costs are evaluated in the context of comparison of one control over another, if necessary. Except where noted on the issue of wet versus dry FGD, there are no differences that affected the BACT decision.

84. SWEPCO has not provided any information regarding additional "other costs," such as regional air quality compliance or non-compliance costs. A proper BACT analysis requires consideration of the energy, environmental, and economic impacts and other costs. 42 U.S.C. § 7479(3). By failing to consider other costs associated with the technology and emissions proposed for the Turk plant, the BACT analysis is defective and incomplete. The BACT analysis also is defective and incomplete because of the failure to compare other costs associated with the technology and emissions proposed for the Turk plant with other costs associated with alternative control technologies and related emissions calculations, Each of these failures constitutes continuing violations of 42 U.S.C. § 7475(a)(4).

Response:

There is no such regulatory requirement to consider "other cost" in this manner. BACT is not required to evaluate costs in the stated manner of absolute costs; rather costs are evaluated in the context of comparison of one control over another, if necessary. Except where noted on the issue of wet versus dry FGD, there are no differences that affected the BACT decision.

Compliance and Monitoring

85. The cooling tower limits are not enforceable. Particulate emissions coming out of the tower depend on the drift rate, circulating water flow rate, and total dissolved solids ("TDS") in the circulating water. Particulate emissions must be measured in the tower exhaust or calculated from the circulating water rate, TDS in the circulating water, and drift rate. The permit does not require any monitoring or recordkeeping for any of these variables.

Response:

ADEQ agrees that requirements for monitoring TDS in the circulating water are necessary for compliance and will be added to the permit.

86. The commenter made generic comments that the application did not assess the practical enforceability of emission limits and standards.

Response

The ADEQ in its draft permit decision evaluated the appropriateness of continuous emission monitors (CEMS), stack testing, design features, monitoring and recordkeeping that is necessary to enforce the limits and standards in the permit.

The draft permit decision contained the elements the ADEQ deemed necessary to make the permit enforceable. Some additions and changes were made as a result of comments received and they are stated elsewhere in this document. They include, but are not limited to, changes to the road monitoring plan, testing for all HAPs listed in Specific Condition 2 of the permit, and, monitoring of TDS in cooling tower water.

The comment fails to cite any specific conditions or source requirements as being inadequate.

87. ADEQ should require CEMS for PM and mercury, continuous emissions monitoring systems (CEMS) are widely available and in use today

Response

A CEM for mercury will be required as part of the 112(g) MACT approval.

PM CEMs are not well established. From Amendments to New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units and Industrial - Commercial-Institutional Steam Generating Units; Final Rule in the Federal Register / Vol. 72, No. 113 / Wednesday, June 13, 2007 / Rules and Regulations, page 32711

> **EPA is retaining the provision, established in the February 27, 2006 final rule, allowing the optional use of PM continuous emission monitoring systems (CEMS) to steam generating units for demonstration of compliance with rule requirements related to controlling PM emissions. Owners and operators choosing to install and properly operate PM CEMS must demonstrate compliance with the applicable PM emission limit on a daily basis and are not required to install a continuous opacity monitoring system (COMS) or to monitor PM control device performance. We recognize that experience using PM CEMS at electric utility power plants in the United States is limited, and not all affected owners and operators will choose to use PM CEMS.**

Additionally, from 40 CFR 63.1209(a)(1)(iii):

> **(iii) You must install, calibrate, maintain, and operate a particulate matter CEMS to demonstrate and monitor compliance with the particulate matter standards under this subpart. However, compliance with the requirements in this section to install, calibrate, maintain and operate the PM CEMS is not required until such time that the Agency promulgates all performance specifications and operational requirements applicable to PM CEMS.**

Although PM CEMs are available, there is no standard and their use is deemed optional by the US EPA.

88. The permit should clarify how continuous compliance with PM limits is determined.

> The commenter requests an explanation from ADEQ as to why Method 17 was not selected as the test method. Continuous emissions monitoring systems (CEMS) are the preferred method for determining compliance with PM limits. 40 CFR §§ 60.42, et seq.
>
> Continuous opacity monitors (COMs) will be used to determine continuous compliance with the plant's separate opacity limits. If ADEQ considers opacity as a surrogate for PM, then the draft permit must include a specific provision describing the exact opacity level (expressed as percentage, e.g., 5% or 10% opacity) that corresponds to a PM exceedance. The commenter asserts that any exceedance of a separate applicable opacity standard is evidence of an exceedance of the plant's applicable PM limit. The commenter requests that ADEQ confirm that this is so.

Response:

Regarding the use of Method 17, the method states:

> **Applicability. This method is applicable for the determination of PM emissions, where PM concentrations are known to be independent of temperature over the normal range of temperatures characteristic of emissions from a specified source category. It is intended to be used only when specified by an applicable subpart of the standards, and only within the applicable temperature limits (if specified), or when otherwise approved by the Administrator. This method is not applicable to stacks that contain liquid droplets or are saturated with water vapor. In addition, this method shall not be used as written if the projected cross-sectional area of the probe extension-filter holder assembly covers more than 5 percent of the stack cross-sectional area (see Section 8.1.2).**

The test method is referenced in subpart Da as an acceptable method under certain conditions. Method 17 would be an acceptable test method if the conditions of subpart and test methods regarding stack temperature and moisture are met. Because the method operates the filter at the stack temperature and the stack temperature is lower than a heated filter box temperature in Method 5 (approximately 250 F versus a stack temperature of 190 F), the test would be biased high considering condensibles. But since the applicant is also required to conduct a Method 202 which captures condensibles there will be no overall difference in tested emission rates.

Regarding PM CEMs, the state of continuous PM emission monitors is not the point where a PM CEM can be required. See the previous comments on this matter.

The ADEQ has determined that annual testing for PM is adequate.

Opacity and PM, although related, are not the same and an exceedence of an opacity limit is not an automatic exceedence of a PM limit, although it may be an indicator. The Department is not proposing establishing a relationship between opacity and PM emission rates.

89. Unless CEMS are required, the final permit should require semi-annual stack testing for PM, VOCs, CO, Pb and H2SO4 annual stack test is required, but a once-a-year test is insufficient to assure compliance. The draft permit fails to assure compliance with PM, VOCs, lead, CO, and mercury limits.

> If ADEQ does not requires PM CEMS and fails to add a provision describing the opacity level that corresponds to a PM exceedance, then, at the very least, ADEQ should require semi-annual stack testing for PM, in order to meet the minimum, semi-annual, compliance reporting requirements under Title V of the Clean Air Act. Similarly, the only way to assure compliance with the applicable requirements, and to fulfill the federal Title V (Operating Permits) program's semi-annual compliance certification requirements, would be for the Turk plant to conduct at least semi-annual stack testing for all pollutants not continuously monitored.

Response:

A continuous monitor for CO is required in the permit. Mercury emissions are set by the MACT requirements as established by the 112(g) permit decision (i.e. 1.7 lbs mercury/trillion Btu heat input). A continuous emission monitor (CEM) will be used to continuously measure mercury emission rates from the boiler stack.

The Department has determined that annual testing is sufficient for the other pollutants listed.

As discussed previously, PM CEMs are not required. The low VOC levels and absence of controls to meet the level do not warrant a CEM. There are no known Pb (lead) or H_2SO_4 continuous monitors for power plants available.

It is inaccurate to state that the semi-annual "compliance certification" necessitates semi-annual testing. This is actually a semi-annual report of all monitoring required in the permit. The compliance certification is an annual requirement contained in General Condition 21 of the draft permit, refer to 40 CFR 70.6(a)(3) and Regulation 26.701(C)(3). The annual compliance certification does not mandate that every emission listed in the permit have a continuous emission monitor or an actual stack test to assure compliance with the limit.

90. The commenter stated that monitoring of mercury and beryllium in the coal must be conducted and required in the permit on a routine basis.

Response

A continuous emission monitor (CEM) will be used to continuously measure mercury emission rates from the boiler stack. The content of mercury in the raw coal is not a good indicator of actual emissions. Due to this and the presence of a CEM for mercury, coal monitoring for mercury will not be required in the permit.

Beryllium limits are set in Specific Condition 2 of the draft permit. Beryllium is also defined as a Hazardous Air Pollutant and subject to regulation under 112(g). Since beryllium will be emitted as a particulate from the stack it was included in the particulate (PM_{10}) limits of the 112(g) analysis.

There is no known CEM for beryllium. Though not specifically designed for the purpose of controlling beryllium, it will be controlled to some extent by the air pollution control system and measuring beryllium in the raw coal is not a good indicator of actual emissions. Instead, a condition requiring an annual stack testing for beryllium and other pollutants has been added to the permit.

Mercury

91. The commenter stated mercury emissions are higher compared to another pulverized coal power and need to be controlled to the same level on a megawatt basis. The draft permit establishes a mercury limit that is higher than SWEPCO has shown it can achieve. The draft permit TPY limit (0.018) is higher than the NSPS allows (0.173 tpy)

Response

Since ADEQ issued the draft permit, SWEPCO has applied for and ADEQ has issued a draft decision regarding mercury and other HAPs in accordance with 112(g) of the Clean Air Act. This action reduces allowable mercury limits to 1.7 lbs mercury/trillion Btu heat input, equivalent to the lowest limits found in any similar permitted sources. Details are available in the application, draft decision and other comments in this document specifically related to the 112(g) permit.

The difference in the 0.18 and 0.173 figures was a round up issue. It is no longer relevant with the lower limits of the 112(g) decision.

92. SWEPCO also failed to provide a complete certificate of representation for a mercury designated- representative for the Turk plant. This failure constitutes continuing violations of 40 C.F.R. §§ 60.4110 and 60.4113.

Response

On February 8, 2008, the U.S. Court of Appeals for the D.C. District vacated the U.S. EPA's Clean Air Mercury Rule (CAMR) which established a mercury cap-and-trade program for new and existing electric generating units (EGUs) and allocated mercury allowances to states. (State of New Jersey, et al. v. EPA, 517 F. 3d 574 D.C. Cir. 2008)

The court decision means that each EGU will have to meet Maximum Achievable Control Technology (MACT) standards. The EPA's cap-and-trade approach to regulating mercury emissions has been eliminated. A certificate of representation for a mercury designated representative was required under the cap-and-trade program. As this program is no longer permitted, a certification to operate under the cap-and-trade program is not required.

93. SWEPCO has failed to conduct such monitoring as necessary to determine the effects mercury emissions will have on air and water quality in those areas affected by mercury emissions from the Turk plant, including but, not limited to the relevant Class I areas. This failure constitutes continuing violations of 42 U.S.C. § 7475(a)(6) and 40 C.F.R. § 52.21(m).

The draft permit would authorize mercury emissions that would degrade waters of the state, including Outstanding Resource Waters. Arkansas law provides that no degradation may be allowed for Outstanding Resource Waters, and any additional mercury loading will degrade such waters.

There has not been a proper analysis of air quality impacts from mercury projected for the area as a result of the growth associated with the Turk plant, which constitutes continuing violations of 42 U.S.C. § 7475(a)(6), 40 C.F.R. § 52.21(m).

Response

The effects of mercury were evaluated in the report to the Arkansas Public Service Commission (PSC), John W. Turk, Jr. Power Plant TRC Discussion of Mercury Emissions, Deposition, and Human Health Risk Analyses Stemming from Arkansas PSC Hearing – Docket 06-154-U, February 2008; the facility considered the impacts of mercury and concluded that any impacts would be acceptable.

The regulatory reference in the comment does not include a growth analysis as described by the commenter. Growth analysis would be required under 40 CFR § 52.21(o). This was included in the permit application in section 7.4.1.

Other General Comments

94. The commenter made generic comments that the application does not comply with the Clean Air Act and Arkansas law.

Response

The comment contains no specific detail. The application was evaluated in accordance with all applicable requirements and regulations.

95. The commenter questioned whether the facility would apply for a second unit and avoid regulation by segmenting the project.

Response:

The application was submitted for the single unit with no references to an additional unit. The ADEQ evaluated the application submitted. There is no justification or authority to evaluate the impact of a second unit if none is proposed at this time. If a second unit is proposed it will be evaluated in accordance with all applicable regulations.

96. The proposed Turk plant will violate Arkansas law, Ark. Code Ann. § 8-3-103 regarding hydrogen sulfide emissions.

Response

There is no evidence of H_2S emission from the facility or evidence that any emissions, should they occur, would exceed the ppb ambient standards in the cited law.

97. A fair and sound evaluation of the proposed action must encompass not only permitted activities and actual plant construction and operation, but also appurtenant operations such as movement of coal to the site, location of transmission lines, the probability of sequential plants in Hempstead County and the possibility of lignite mining in south Arkansas to provide a blending fuel to augment imported Wyoming coal and as a primary fuel source for new electric power facilities.

Response

Such activities are outside the regulatory authority of this permit. This permit is limited to activities at the source as they relate to air emissions.

98. A comment period extension is needed for any additional SWEPCO modeling. SWEPCO's permit application should be denied. In the alternative, and because of the incomplete state of modelings, BACT analysis and other matters, Commenters respectfully submit SWEPCO should be required to complete its permit application in compliance with all applicable laws and regulations, and that a new 30 day comment period commence after completion of those requirements.

Response

The procedures for issuing a draft permitting decision are set forth in APC&EC Regulation 8.2.1 *et seq.*. Regulation 8 requires the Director to publish notice of a proposed draft permitting decisions and provide: (1) the name and telephone number of the division of the Department responsible for the draft permitting decision; (2) the name and business address of the permittee; (3) the type of action for which the permitting decision is proposed to be issued; (4) the date of the issuance of the draft permitting decision; (5) a brief summary of the draft permitting decision; (6) a statement that the draft permitting decision is available for copying at the Department; and (7) a statement that the submission of written comments by any person will be accepted by the Department during the public comment period.

Similarly, Regulation 19 and 26 require the Department to give the public an opportunity to comment on information provided by the permit applicant and any information developed by the Department in support of its draft decision.

All applicable regulations were followed by the Department in issuing notice of the draft permitting decision.

During the public comment period, persons are permitted to copy or inspect the draft permitting decision and other material relevant thereto and submit written comments, data, view or arguments on the draft permitting decision. Those persons that submit public comments are given standing to appeal final permitting decisions made by the Department.

The Southwestern Electric Power Company ("SWEPCO") submitted an application to ADEQ for a Title V air permit to operate the Turk plant on August 8, 2006. The Department determined that SWEPCO's application met the requirements of APC&EC Regulations 8 and 26 and a proposed draft permitting decision was issued on June 12, 2007. The deadline for public comments was extended twice. Written comments were accepted until the close of business on August 6, 2007.

Commenters have asserted that ADEQ should not have issued a proposed draft permitting decision until after it reviewed all air modeling data and completed the technical review of the permit application. ADEQ disagrees. The issuance of a proposed draft permitting decision did not foreclose the Department from considering information after the proposed draft permitting decision was published. Reg. 26.407 specifically provides as follows: "If while processing an application that has been determined or deemed to be complete, the Department determines additional information is necessary to evaluate or take final action on that application, it may request such information in writing..." Similarly, the applicant is under a duty to update incorrect information and supplement any relevant facts that may have been omitted. Reg. 26.409. Arkansas law does not require ADEQ to provide notice and a comment period on everything that it reviews after it issues a draft permitting decision. If ADEQ could not change the conditions of a permit after receiving comments or additional information, it would be placed in the

position of either being unable to learn from the comments and information or being forced to commence new comment periods *ad infinitum*.

Although commenters' have suggested that ADEQ should have started the review process over and issue a new draft permitting decision, ADEQ's consideration of additional information after the close of the public comment period has not interfered with the commenters' right to raise any legal and factual objections that have been raised in the public comments or to those that could not have been discovered and raised during the public comment period. Ark. Code Ann. § 8-4-205(b)(2). Because extensive comments were submitted regarding SWEPCO's air modeling all commenters have standing to raise these issues upon appeal.

There would have been a significant impact on the public had ADEQ re-issued the proposed permitting decision in one document as requested by commenters. If ADEQ issued a subsequent single proposed permitting decision, all those persons that had submitted previous comments would have had to submit new comments.

99. Numerous individuals commented that mercury emissions from the plant will contribute to or cause a noticeable increase of cases of infants with mercury related neurological damage.

> Some individuals commented that emissions from the proposed plant will have a negative effect on public health such as increase rates of neurological disorders, asthma, and cancer.

The Arkansas Department of Health (ADH) indicates a Minimal Risk Level (MRL) of 0.2 micrograms/cubic meter (ug/m3) is used for chronic-duration exposure (365 days or more) to metallic mercury (also known as elemental mercury) vapor. An MRL is defined as an estimate of daily human exposure to a substance that is likely to be without an appreciable risk of adverse noncarcinogenic effects over a specified duration of exposure. An MRL is considered to represent safe levels of exposure for all populations, including sensitive subgroups.

Furthermore, the United States Environmental Protection Agency (USEPA) has derived an inhalation reference concentration (RfCi) of 3x10-4 milligrams/cubic meter (mg/m3) for metallic mercury (0.3 ug/m3). In general, the RfC is an estimate (with uncertainty spanning perhaps an order of magnitude) of a daily inhalation exposure of the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. The RfCi for mercury is based on a lowest-observed-adverse-effect-level (LOAEL) of 0.025 parts per million (ppm). LOAELs are concentrations below which no adverse effects have been observed. Based on this RfCi, USEPA has derived a Residential Air Screening Level of 0.31 ug/m3.

SWEPCO's total mercury emission rate is 0.0102 lbs/hr on an annual average. Using this rate and accounting for a 1 hour versus annual rate, dispersion modeling

predicts ambient air impacts of 0.0028 $\mu g/m^3$ 1 hour average. This predicted concentration is far below the maximum levels established by ADH and USEPA that are protective of public health.

100. Numerous individuals commented that alternative means of providing energy (i.e. solar, nuclear, and wind) should be utilized as opposed to building a pulverized coal fired plant.

Response

Alternatives to the proposed plant are outlined in previous responses.

101. Numerous individuals commented that the proposed site of the plant will degrade the air and water quality of surrounding undisturbed wilderness.

Response

The ADEQ has evaluated the facility's emissions in accordance with proscribed regulations and procedures to assure that no adverse environmental impacts will occur.

102. Several individuals commented that Arkansas should not suffer environmental degradations to benefit a customer base which is largely out of state. We should not frame the issue as the environment vs. economic development. These jobs often turn out to promise a lot and not produce very much. Several commenters stated that the facility would cause long term economic detriment.

Response

The ADEQ has no authority to regulate the facility based on customer base, or employment opportunities, economic benefit or detriment. ADEQ's authority is limited to assuring that the facility complies with all applicable laws and regulations.

103. Several individuals commented that electric utilities should not be allowed to build new plants unless CO_2 emissions are controlled.

Response:

ADEQ has no authority under state or federal law to prevent the construction of power plants based on the control or non-control of CO_2 emissions.

104. One person commented that it is not coal but pulverized coal that causes the problems.

Response

The comment is noted. The commenter makes no reference to any specific aspect of pulverized coal that is not adequately regulated in the air permit.

105. One individual requested clarification as to what law authorized the sale of pollution credits.

Response

The comment does not specifically mention a pollutant or specific instance of pollution credits. In general, the Clean Air Act and regulations codified in 40 CFR contain requirements and allowances for emission trading.

106. One person stated coal and lime will be exposed while being transported and emitted into the environment. Another commenter was concerned about the coal trains impacting vehicle traffic in the areas where the coal train goes through towns like Ashdown.

Response

The ADEQ air permit has no authority to regulate the transportation of lime or coal.

107. Does ADEQ intend to approve SWEPCO's plant construction without all necessary pollution controls in the initial design?

Response

Construction of the plant is not allowed until the facility has a permit that specifies all applicable requirements and controls. The facility must then be constructed in accordance with the permit.

108. If allowed to be built, what would be the cap on emissions? If there are no caps, then why not?

Response

Emissions and emission limits are set forth in the draft permit. A summary page is included starting on page 20 of the draft permit and is in the final permit.

109. One person commented that coal combustion at this plant alone will produce 13 tons of radioactive uranium and thorium annually.

Response

There is no evidence to support this claim, and the commenter does not indicate the location of this emission (i.e. main boiler, etc).

110. One comment stated that SWEPCO will emit a large amount of CO_2. It is a deadly poison and will kill you if you breathe it.

Response

The Turk plant will emit CO_2. CO_2 is universally found in the ambient air of the planet. Carbon monoxide (CO) is a deadly poison at certain concentrated levels. CO emissions are regulated in the permit.

111. One person commented that the smoke stacks are disruptive of aesthetic quality of the view.

Response

The ADEQ air permit has no authority to regulate the aesthetic quality of the smoke stack.

112. One person commented that ADEQ's determination for BACT for SO_2 is correct. The comment cited the following:

(1) properly included not only SO_2 emission levels but also energy, environmental, and economic factors,
(2) correctly concluded that SO_2 BACT for the plant is dry FGD, and
(3) cannot be invalidated by the EPA. (ADEQ made proper BACT determinations)

Response

The comment is noted, however EPA can object to any permit issued by ADEQ, in accordance with the Clean Air Act. In such a case, specific rules apply to the appeal process.

113. Several individuals commented that they supported construction of the power plant because the plant will create jobs.

Response

The comments are noted.

114. Please lend support to better environmental controls, less impact to ecologically sensitive areas, reduced consumption, and increased use of renewable energy.

Response

The ADEQ has evaluated the facility's emissions in accordance with all applicable laws, regulations and procedures to assure that all environmental requirements have been met.

The Department does not have the authority to address the implementation of energy conservation requirements on the part of the public in an air permit.

The Department does not have the authority in an air permit to mandate where a facility will be located.

115. Consider the ThermoEnergy Integrated Power System "TIPS" a process to convert coal to energy with no air emissions.

Response

The referenced company's web site indicates this process is in the research stage. It is not available for consideration in this air permit.

116. Real accountability would entail a much higher level of preparation for sequestration then (sic) SWEPCO has indicated so far that it's prepared to provide. The unit should not be built without carbon sequestration.

Response

Carbon sequestration is not an available technology at this time. SWEPCO has indicated that the design of the plant includes the designation of approximately 20 acres in the plot plan for future CO_2 capture equipment. They also state that a preliminary study of the site geology indicates it is a candidate to support sequestration.

117. The plant should be built in a "developed" area instead of disrupting one of the few natural habitats left. The commenter stated that facilities like power plants and other industrial facilities tend to locate in similar communities due to the "Cerrell Effect".

Response:

The Department does not have the authority to determine where a facility will be located.

118. Energy conservation efforts should be done before building this plant.

Response

The Department does not have the authority to incorporate conservation efforts into air permit considerations

119. Arsenic, selenium, chromium and carcinogenic organic compounds can leach into the groundwater supply from solid waste produced by coal fired plants.

Response:

Groundwater contamination from the solid waste landfill is not germane to the air permit. A solid waste permit will be required; such considerations will be addressed in that permit evaluation.

120. The commenter states that the emissions from coal fired power plants cause asthma.

Response:

The commenter did not provide any information to substantiate this claim.

121. Commenter state that constructing the facility will increase electricity rates and health insurance rates.

Response:

The Department does not have the authority to consider the potential increase or decrease of electricity rates or insurance rates.

122. The commenter does not want the facility built due to visual and olfactory problems.

Response

ADEQ does not have the authority to deny a permit based upon aesthetics.

123. The commenter is concerned that the air in Arkadelphia would be adversely affected by the emissions from the facility and would cause acid rain.

Response:

The applicant performed modeling that showed the emissions would not cause violations of the NAAQS in Arkadelphia, and the permittee is subject to the requirements of the federal Acid Rain Program, section 821.

124. The commenter objects to the mining of coal and black lung disease among miners.

Response:

ADEQ has no authority to stipulate how the coal used is mined or consider environmental impacts from coal mining that is not conducted at the facility. ADEQ does not have regulatory authority to regulate coal miners' exposure to coal dust.

125. The commenter wants the facility to use locally grown biomass as a feedstock for gasification or co-firing biomass with coal.

Response:

The Department does not have the authority to specify the fuel for the facility.

126. The commenter requested ADEQ to distribute information on how to reduce energy requirements and how to support the development of non-toxic, sustainable energy.

Response

The ADEQ website has links to other organizations that show how to reduce energy at <u>ADEQ - Links to Other Environmental and Government Sites</u>.

127. The commenter states that ADEQ, EPA or Texas conduct air monitoring in the area and that the air is already unsafe to breathe.

Response:

Texas has a $PM_{2.5}$ monitor in Texarkana. The monitor has not detected a violation of the NAAQS.

128. The commenter states that the facility was forced on the area and regional citizens unannounced.

Response

The facility was announced to the area in ten day notice published on August 21, 2006 in the Hope Star, a thirty day public notice for the draft permit published in the *Arkansas Democrat-Gazette* on June 12, 2007 and in the *Hope Star* on June 14, 2007, and a public hearing was held on July 12, 2007. The Department complied with all requirements for public notice.

129. The commenter voices a concern about water withdrawal from the Little River increasing salinity and impacting Interior Least Terns and Ouachita Rock Pocketbook Mussels.

Response:

The air permit is not the proper venue to raise concerns about water withdrawal issues.

130. The commenter requested a cost/benefit study and an Environmental Impact Statement.

Response:

An EIS was submitted on December 8, 2006 (and revised on April 19, 2007) to the PSC as part of the application for a Certificate of Environmental Compatibility and Public Need.

No other EIS is required for this project.

131. Comment

The Arkansas Department of Historic Preservation (ADHP) reviewed the area for archeological sites located in the area of the plant site. The ADHP recommended that one area is eligible for inclusion in the National Register of Historical Places. The ADHP is also concerned about historical sites being impacted by auxiliary construction of roads and railroads.

Response:

The concerns of ADHP are noted.

Comments by the Applicant (SWEPCO)

132. Page 16 and 29 – The maintenance exclusion for the scrubber should be clarified in the permit. In the SO_2 row add "(DFGD)" after "Dry Flue Gas Desulfurization."

Response:

No justification to relaxation of limits for "maintenance" has been provided. The exclusion of "maintenance" events from emission limit requirements has been removed from the permit. The facility must comply with the stated limits at all times or report any deviations in accordance with reporting requirements contained in the permit.

133. Page 17, Paragraph 2, Line 6 – The auxiliary boiler is a Subpart Db unit and is not covered by Subpart Da. Since the boiler only combusts natural gas and has a capacity factor less than 10% it is not required to have a NOx CEMS.

Response:

The reference to Subpart Da will be corrected. The BACT portion of the permit application states that compliance with the NOx limit shall be demonstrated via CEMS. SWEPCO has since requested that an initial test, restriction to natural gas as a fuel and 10% capacity limit factor be incorporated in the permit.

Since the subpart Db does not require a CEM under such conditions the Department will remove the CEM requirement in lieu of the alternative proposal. However, the ADEQ deems an initial test only as insufficient. Based on the limiting operations and emissions of the unit, testing will be every 5 years instead of the proposed initial test only.

134. Page 20 – Add NSPS Subpart Db as an applicable regulation.

Response:

The Department agrees. The change has been made.

135. Page 27, Specific Condition 1, Line 3 – Please remove CO from the stack testing requirements. The permit requires a certified CO CEMS on the stack and CEMS is identified as the compliance method.

Response:

The Department agrees. The change has been made.

136. Page 27, Specific Conditions 1 and 2 - Please clarify that compliance with the PM/PM_{10} limits will be determined by SC 5 (stack test), and that a compliance demonstration for PM and VOCs per SC 5 will demonstrate compliance for all the other compounds included in the tables that are specifically identified as components of the PM and VOC emissions (including Pb). SC 7 is only used as a compliance determination method for SO_2, NOx, and CO. To avoid confusion, these tables could be combined into a single table with the compliance determination methods identified in an additional column, as is done in SC 3.

Response:

The condition has been changed to show that compliance with the CO emissions shall be shown through compliance with Specific Condition 8, not Specific Condition 5. Pb has a distinct BACT limit and compliance with that rate must be demonstrated independently of the PM emission rate. The testing requirements for the compounds on an individual basis shall remain as written.

137. Page 28, Specific Condition 3 – Reference Method 9 is correctly identified as the compliance method for opacity in the permit. However, the second sentence in this

condition should be clarified to state that COMS will be used as an indicator of good operation and maintenance of the control equipment.

Response:

The permit shall remain as written. The facility is required to be equipped with a COM and the COM is used to determine compliance with the opacity limit.

138. Page 29, Specific Condition 4 – There should only be two rows for PM/PM_{10} in the table – one for "PM/PM_{10} (filterable)" and one for "PM/PM_{10} (total)". The "controlled Condensate method" should be added to the table as a compliance method for sulfuric acid mist.

Response:

The Department agrees to the change. There is no difference in the alternate methods of expressing these limits

139. Page 29, Specific Condition 5 – Testing Annually for PM and VOC is not necessary. After the initial compliance test is performed within 180 days of commencement of operation, one additional test during the term of the permit is sufficient to show compliance. Testing for lead (other than the initial test) is not necessary since compliance with the PM limit is a proper surrogate to show compliance. Testing for sulfuric acid (other than the initial test) is not necessary since compliance with the SO_2 limit is a proper surrogate to show compliance. CO appears to have been inadvertently included in this table, and should be removed since a CEMS is required, as reflected in the Table in SC 4.

Response:

The CO testing requirement has been removed from the table due to the requirement for a CEM. Annual testing for PM and VOC shall remain a requirement since there is no other requirement for on-going means of demonstrating compliance with the BACT limits, such as CEMs.

140. Page 30, Specific Condition 5 – Please add "Controlled Condensate Method" as an acceptable test method for sulfuric acid.

Response:

The Department agrees. The change has been made.

141. Page 30, Specific Condition 6 – Change Method 206 to Method CTM-027. Testing for these compounds annually is unnecessary. They should be tested initially and once more during the term of the permit.

Response:

The test method for ammonia has been changed. The annual test requirement shall remain in the permit since there is no other requirement for on-going means of demonstrating compliance with the limits, such as CEMs.

142. Page 39, Specific Condition 15 – The auxiliary boiler opacity limit should be changed to 20% to be consistent with Regulation 19, §19.503. However, NSPS Subpart Db requirements recognize that gas-fired combustion sources with potential SO_2 emission rates of 0.32#/MMBtu or less need not comply with PM or opacity requirements. 40 CFR §60.44b(i)(5). This condition should be removed from the permit based on the same rationale pursuant to Regulation 19, §19.505. No monitoring or reporting of opacity or PM should be required for this source due to the very low emissions and limited operating hours associated with this unit.

Response:

Opacity is a PSD limit thus the 19.901 reference. The 10% limit is consistent with BACT. No monitoring or reporting is required. Compliance is shown through the use of natural gas as fuel. The permit shall remain as written.

143. Page 39, Specific Condition 17 – Instead of a 12 month hourly limit of 500 hours of operation, AEP proposes a 12 month fuel usage limit of 27,500 MMBtu. This provides greater flexibility and still maintains the same emissions limits.

Response:

The permit application lists the maximum annual heat input as 277,500 MMBtu. The Department will change the limit to a 12 month fuel usage of 272.1 MMscf.

144. Page 40, Specific Condition 18 – Based on the above request regarding SC 17, the type of recordkeeping required by SC 18 should also be changed to track monthly fuel usage.

Response:

The recordkeeping will be changed to require the facility to track the MMscf of natural gas used at this source.

145. Page 40, Specific Condition 20 – Subpart Da is not applicable to the auxiliary boiler. Subpart Db is the applicable Subpart. The auxiliary boiler does not produce electricity; therefore it falls in the classification in Db of an industrial steam generating unit.

Response:

The Department agrees. The change has been made.

146. Page 60, Specific Condition 30 – The opacity observation required in this paragraph should be performed within 180 days of the commencement of operation of the source.

Response:

The Department agrees the opacity observation should be performed after the commencement of operation of the source. However, the reading will be required within 90 days of the commencement of operation of the source.

147. Page 61, Specific Condition 33 – Change to "…total of 100 non-emergency hours during…" This is consistent with the MACT limit for emergency engines.

Response:

SWEPCO has withdrawn this comment.

148. Page 64, Specific Condition 38 - The opacity observation required in this paragraph should be performed within 180 days of the commencement of operation of the source.

Response:

The Department agrees the opacity observation should be performed after the commencement of operation of the source. However, the reading will be required within 90 days of the commencement of operation of the source.

149. Page 71, Specific Condition 47 – Change to "…rates are based on the maximum…"

Response:

The Department agrees. The change has been made.

150. Page 71, Specific Condition 48 – Change to "…rates are based on the maximum…"

Response:

The Department agrees. The change has been made.

151. Page 75, Specific Condition 54 - This condition requires stakes, monuments, or other permanent markers to be installed within the working face of the landfill. Such procedures will not promote compliance with the air emission limitations contained in the

permit, and will interfere with ongoing operations and/or could introduce hazards into this working area. The provisions in SC 56 are adequate to assure that fugitive emissions at the landfill are well-controlled. SWEPCO requests that this condition be removed and that consideration of appropriate measures to assure that the operating area is maintained at 50 acres or less be addressed in the solid waste permit for the landfill.

SWEPCO has since modified this comment. The applicant proposes alternative language of:

(a) The permittee shall minimize fugitive particulate matter emissions from the solid waste disposal area, SN-F-06, through the use of water or other dust suppressant, or implementation of work management practices as necessary.

(b) At a minimum, the frequency of fugitive particulate matter minimization activities shall occur daily when the area is in service unless otherwise required as a result of inspections required by (c) below.

(c) Daily inspections of solid waste disposal area when the area is in service shall occur to determine the needed frequencies of fugitive particulate matter minimization activities. If the inspection observations determine that the disposal area is covered with snow and/or ice, that precipitation has occurred that is sufficient for that day to ensure fugitive dust has been minimized, or that additional action is not necessary to minimize fugitive particulate emissions, then the requirements of section (b) shall not apply.

(d) The facility shall maintain records of these daily inspections including observed conditions and actions taken.

Specific Conditions #55 and #56 should be deleted in lieu of the aforementioned proposed revisions to Specific Condition #54.

Response:

The suggested language does not guarantee that there will be no off-site opacity impacts, just that the dust is "minimized". Nor does the suggested language limit the size of the landfill and thus its overall impact and predicted emissions. However, ADEQ recognizes the impractibility of stakes and other items on an active landfill. Therefore ADEQ will just require a certification every 6 months to be included in the required semi-annual reporting that the active area is 50 acres or less.

152. Page 75, Specific Conditions 55 and 56 - There are no applicable opacity requirements for these types of sources in the federal NSPS or Regulation 19. Opacity requirements under both programs apply only to specifically identified sources. SC 55 and 56 should be eliminated.

Response:

ADEQ disagrees that opacity cannot be regulated from operations at the landfill. However, the conditions are unclear on the exact compliance mechanism and a 20% opacity is not measurable by any EPA test method for fugitive sources. Specific Condition 55 and 56 has been changed to require the permittee to conduct operations in such a way that there will be no off-site visible emissions from the sources per EPA Method 22.

153. Page 80, Plantwide Condition - The auxiliary boiler is the only source required to prepare and implement a startup, shutdown, and malfunction (SSM) plan. This condition should be moved to the SC's under the auxiliary boiler section.

Response:

The Department disagrees that the condition should be moved. Since the main boiler and auxiliary boiler are both subject to the requirements of 40 CFR 63, both require a SSM plan in accordance with 40 CFR 63.

154. Page 81, Plantwide Conditions 8 and 9 - These conditions are not necessary to assure compliance with the applicable requirements at this facility and are inconsistent with the capacities used to estimate emissions at the source. Emissions on the main boiler are monitored by CEMS or through periodic stack testing. Coal and other material handling emissions are subject to specific work practices. In addition, reliability obligations may require that coal be stockpiled in advance of transportation constraints or threatened delivery disruptions. These conditions artificially constrain the coal handling system because their maximum capacity, as presented in the application, are (sic) typically much larger than the 3,285,000 tpy permit limit. These conditions should be eliminated.

Response:

The Department agrees. These conditions have been removed from the permit.

RESPONSE TO COMMENTS MACT 112(g) PERMIT

John W. Turk, Jr. Power Plant
112(g) Application
PERMIT #2123-AOP-R0
AFIN: 29-00506

On August 11, 2008, the Director of the Arkansas Department of Environmental Quality gave notice of a draft permitting decision for the above referenced facility. During the comment period, written comments on the draft permitting decision were submitted by various parties including the applicant.

The following comments are summarized from all comments received. For the original and full text of comments, please refer to the record containing the full text of comments. The Department's response to these issues follows.

Note: The following page numbers and condition numbers refer to the draft permit. These references may have changed in the final permit based on changes made during the comment period. One commenter incorporated by reference comments made on the initial MACT submittal, many of the comments are not applicable based on subsequent revised submittals by the applicant.

General Comments

1. At a minimum, the Turk plant must meet the MACT "floor" for all its HAP emissions. To be clear, the actual level of performance of the best performing source *is* the MACT floor, even if the regulator cannot identify how the source actually achieves its emissions control, or even if the best performing source does not intentionally control emissions at all.

   Response

   ADEQ acknowledges the comment and qualifies the comment by stating that the actual level of performance of the best performing *similar* source is the MACT floor.

2. ADEQ must determine the "best controlled similar source" and hold SWEPCO to at least those levels, regardless of cost.

   SWEPCO has failed to provide sufficient justification for what constitutes a "similar source".

For each case, SWEPCO needs to make the case for determining what a similar source is and what needs to be considered. Type of coal and plant designs need to be considered. This evaluation should be specific to each pollutant because the pollutants, air pollution controls and plant design will affect the determination of "similar source".

Response:

ADEQ agrees that the basis for emission limits is at least the "best controlled similar source."

A similar source is one that is similar in design and capacity. 40 C.F.R. 63.41

A similar source is one that has similar emission and similar emission controls. From page 3-21 of Guidelines for MACT Determinations under Section 112(j) Requirements, EPA 453/R-02-001

> **Sub-categorization within a source category for the purposes of a case-by-case MACT determination should be considered when there is enough evidence to clearly demonstrate that there are air pollution control engineering differences. Criteria to consider include process operations (including differences between batch and continuous operations), emissions characteristics, control device applicability and costs, safety, and opportunities for pollution prevention. When separate subcategories are established, the MACT floor and MACT are then determined separately for each such subcategory.**

In 40 CFR 60 Subpart Da, for the purpose of mercury emission rates, EPA categorizes coal combustion by IGCC/non IGCC and by fuel type for the non IGCC units.

As explained in the application, the coal type and boiler type have the most influence on the controls used. In this case a similar source was defined as the coal type (sub bituminous) and the boiler type, pulverized coal. This is set forth in the application starting on page 10.

<u>Design differences among coal types:</u>

The Department requested information from SWEPCO on the design differences between pulverized coal plants burning sub-bituminous coal versus those burning other types of fuel, including bituminous coal, lignite, petcoke, and waste coal. *See* October 29, 2008 and October 31, 2008, SWEPCO Supplemental Information. It is apparent that the inherent differences in the properties of different types of coal significantly affects the design characteristics of any proposed plant. Of particular significance is the fact that an ultra super-critical pulverized coal plant (USCPC), a highly efficient PC design, is by definition

designed to operate at temperatures above 1100°F. In contrast, bituminous and lignite coals have significantly higher sulfur content requiring a reduction in the design steam temperatures and negating the overall efficiency of the USCPC design. In contrast, use of petcoke and waste coal generally requires the use of Circulating Fluidized Bed design which is fundamentally different from the USCPC design. Based on this information, the Department is satisfied that limiting the consideration of similar sources to PC plants burning sub-bituminous coal was appropriate based on the definition of a similar source.

It is inappropriate to define a "similar source" differently for each pollutant. This would potentially result in non-attainable emission limits and contradictory design requirement. It is appropriate, though, to consider control equipment and techniques across different "similar sources" in going "beyond the floor".

3. ADEQ and SWEPCO are required to look at emissions control levels beyond the MACT floor. There is no evidence that either SWEPCO or ADEQ conducted a beyond-the-floor analysis.

   Response

   Such analysis is included in each pollutant specific section of the application. Section "a.' is a review of technologies and section "d." is the beyond the floor analysis.

4. As written, the draft 112(g) permit does not sufficiently employ the MACT analysis established in the regulations. SWEPCO's analysis and ADEQ's acceptance of emissions limits based on permitting and not on actual performance does not comply with the statutory and regulatory framework established for the MACT review.

Response

ADEQ considered test data and permitted emission rates in establishing MACT limits. Though actual data may be considered there is no requirement to establish limits solely on any one specific test or test(s). The permitting authority has the discretion to consider all available data. That the established MACT limits are not equivalent to the lowest reported test result is due to the fact that much of the actual emission data is of such limited nature that it cannot be used to demonstrate an emission rate on a continuous basis. Details of the analysis are contained in individual sections for each pollutant.

5. The permit has failed to provide any justification for why the proposed draft permit limits are needed, when its own data, and that of ADEQ, clearly indicate that lower limits (i.e. MACT floor) have been achieved at other coal plants.

   Repeatedly throughout the application, and subsequently the permit, the emissions limits set for Turk are higher than the proven achievable limits from other plants.

Response

The comment in general refers to setting a permit limit that is not the lowest value of any reported stack test. Achieved in practice is not necessarily the limit achieved in one stack test. To be considered achieved in practice, the limit must be achieved on a long term basis, not just in an initial or one time 3 hour stack test. Further pollutant specific details on this MACT decision are set forth in subsequent pollutant specific comments.

6. The application and supplements fail to provide sufficient information to satisfy a MACT analysis. The record fails to contain sufficient information about the HAP composition of the fuel, so that it is virtually impossible to adequately determine uncontrolled emissions, let along controlled emissions of HAPs.

   SWEPCO has provided no documentation regarding uncontrolled emission rates or coal composition data. In a May 21, 2008, letter to Tom Rheaume from John Hendricks, SWEPCO admits that several factors impair its ability to estimate uncontrolled emissions, and then boldly (and incorrectly) claims that "uncontrolled emission rates are substantially equivalent to the control [sic] emission rates." This is nonsensical.

   The record also does not disclose the design basis of the proposed MACT control, the spray dryer absorber and the fabric filter baghouse.

Response

The use of uncontrolled emission rates would presume their use in determining a percent reduction by control equipment to establish a MACT limit. This is one available method to establish MACT emission rates. It is not the only method or even the required method. (Controlled) emission rates achieved is another. For example, in the technology approach outlined in Guidelines for MACT Determinations under Section 112(j) Requirements, EPA 453/R-02-001, one method for determining a MACT emission limit is the Technology Approach.

> **4.5 Technology Approach**
> **The technology approach is used when insufficient emissions data are available to determine an average emission limitation. Under this approach, EPA determines which technology is being used by the average of the best performing 12 percent of sources in the category, and then determines the average emission limit that this technology is capable of achieving in practice on a continuous basis. Available emissions data are used to assign a performance value for each emission control identified (percent removal, outlet grain loading, etc.). The MACT floor calculation is performed based**

on these performance values. Typically, a median is used rather than the arithmetic average since an arithmetic average generally would not correspond to any given control. The following example illustrates this approach.

A source category emitting metal HAP is comprised of 500 sources. A survey of the sources finds that 300 facilities use cyclones to control HAP emissions, 150 facilities use wet scrubbers, and 50 facilities use fabric filters. Based on available emissions data, it is determined that cyclones are 25-percent efficient at removing HAP emissions, wet scrubbers are 75-percent efficient, and fabric filters are 99-percent efficient. The best controlled 12-percent of sources would include 10 sources with wet scrubbers and 50 sources with fabric filters. The median corresponds to fabric filters. <u>Therefore, fabric filters would be identified as the MACT floor technology, and an emission limitation would be set based on the available performance data for fabric filters.</u>

Coal is not a uniform substance and compositions can vary. The application estimates emissions based on the EPA compilation of emission factors, commonly referred to as AP-42. Compiling the data of various coal used would not yield any more useful data than the emissions estimates relied upon. It would also not provide information on emission generated as the result of combustion. At best it would give a range of some of the metal constituents, but even there it would not provide useful information due to the partitioning of the metals in ash and air emissions.

The commenter does not state what type of information they would consider necessary about the control equipment in order to affect a MACT decision. In any event, Appendix A, page 16 of the application contains ADEQ forms with the basic operating parameters of the control equipment. Details of the carbon injection system were included in the Second Supplemental Response to comments, dated August 1, 2008. The type of bags used in the fabric filter are included in Page 17 of SWEPCO's Responses to Comments on ADEQ's 112(g) Draft Permit Decision for the John W. Turk, Jr. Power Plant, AFIN: 29-00506 October 8, 2008.

7. The Clean Air Act and implementing regulations require more than that an applicant just name a control technology. Rather, SWEPCO must provide sufficient information to satisfy the permitting authority that it will, in fact, achieve the emissions level of the best controlled similar source. *See* 40 C.F.R. § 63.43(e)(xi) (requiring application to include "technical information on the design, operation, size [and] estimated control efficiency of the control technology.")

Response

The exact requirement of 63.43(e)(xi) is

(2) In each instance where a constructed or reconstructed major source would require additional control technology or a change in control technology, the application for a MACT determination shall contain the following information:

> **(xi)The selected control technology to meet the recommended MACT emission limitation, including technical information on the design, operation, size, estimated control efficiency of the control technology (and the manufacturer's name, address, telephone number, and relevant specifications and drawings, if requested by the permitting authority);**

The proposed plant was evaluated with all the controls necessary to meet the MACT limits in the PSD/NSR permit. The MACT 112(g) permit did not require any additional controls that were not already considered. Activated Carbon Injection may not have been clearly indicated in the PSD/NSR permit. Information on ACI was included in the 112(g) application in the August 1, 2008 supplemental information letter.

8. ADEQ's analysis and determination assumes *a priori* a 600 megawatt pulverized coal (PC) plant, burning sub-bituminous coal, and with the specific pollution control train that SWEPCO proposes. Throughout, SWEPCO and ADEQ have limited the analysis to sub[-]bituminous coals when, clearly, all fuels should be considered. ADEQ's analysis and draft permit should not assume, as a foregone conclusion, the plant that SWEPCO *wants* to build satisfies MACT.

Response

Section 112(d) provides that "[t]he maximum degree of reduction in emissions that is deemed achievable for new sources in a category or subcategory shall not be less stringent than the emission control that is achieved in practice by the best controlled *similar source*, as determined by the Administrator." The CAA does not define the term "similar source."

The EPA has defined a "similar source" as "a stationary source or process that has comparable emissions and *is structurally similar in design and capacity to a constructed or reconstructed major source* such that the source could be controlled using the same control technology." 40 C.F.R. 63.41. Therefore, in determining the MACT floor, ADEQ must consider sources similar in design and capacity. Limiting the MACT floor determination to 600 megawatt pulverized coal (PC) plants, burning sub-bituminous coal is proper because smaller or larger capacity facilities are not similar. Likewise, facilities utilizing other types of fuel—nuclear, hydro, gas, syn-gas, and even other types of coal—are not structurally similar in design. *Prairie State Generating Company*, 13 E.A.D. ___, PSD Appeal No. 05-05 (August 24, 2006) (hereinafter "*Prairie State*"); *aff'd, Sierra Club v. EPA*, 499 F.3d 653, 655 (7th Cir. 2007). The *Prairie State* case was concerned with whether EPA's policy against

redefining the source in the context of BACT was reasonable, the factual underpinnings of the case are applicable here—gas, nuclear, hydro, and IGCC design are structurally dissimilar from an ultra-supercritical PC design.

Design differences among coal types:

The Department requested information from SWEPCO on the design differences between pulverized coal plants burning sub-bituminous coal versus those burning other types of fuel, including bituminous coal, lignite, petcoke, and waste coal. *See* October 29, 2008 and October 31, 2008 SWEPCO Supplemental Information. It is apparent that the inherent differences in the properties of different types of coal significantly affects the design characteristics of any proposed plant. Of particular significance is the fact that an ultra super-critical pulverized coal plant (USCPC), a highly efficient PC design, is by definition designed to operate at temperatures above 1100°F. In contrast, bituminous and lignite coals have significantly higher sulfur content requiring a reduction in the design steam temperatures and negating the overall efficiency of the USCPC design. In contrast, use of petcoke and waste coal generally requires the use of Circulating Fluidized Bed design which is fundamentally different from the USCPC design. Based on this information, the Department is satisfied that limiting the consideration of similar sources to PC plants burning sub-bituminous coal was appropriate based on the definition of a similar source.

9. SWEPCO has also failed to explain its choice of dry versus wet flue gas desulfurization, which affects acid gases and other HAP emission levels.

Response

The Turk plant will employ a dry FGD. The comparison of wet versus dry is contained in Appendix A, which contains information from the May 7, 2008 submittal. The discussion starts on page 31 for mercury considerations and 58 for acid gasses consideration.

The information indicates that dry FGD may control HF and HCl to a higher degree. In any event there is no information to indicate dry FGD would control the gases to a lesser degree than wet FGD.

Mercury will have different removal efficiencies for wet versus dry FGD. However, mercury will be specifically controlled by an ACI system. The difference of wet verses dry does not factor into the mercury MACT emission rate.

10. SWEPCO has failed to identify any cost or non-air quality health impacts as required by 40 CFR 63.43(e)2(xii) that would preclude the use of more stringent controls than those proposed.

Response

The requirement is:

> **(2) In each instance where a constructed or reconstructed major source would require additional control technology or a change in control technology, the application for a MACT determination shall contain the following information:**
>
> > **xii) Supporting documentation including identification of alternative control technologies considered by the applicant to meet the emission limitation, and analysis of cost and non-air quality health environmental impacts or energy requirements for the selected control technology;**

Wet FGD and dry FGD were the only two competing technologies. The costs and non-air quality impacts are contained in the application, Appendix A on page 60.

11. SWEPCO's emission rate tables, dated May 19, 2008, contained in its May 21 submittal, contains proposed maximum emissions levels for several pollutants that are significantly higher than its August 1, 2008, submittal (containing tables purportedly reflecting typographical corrections). There is absolutely no new explanation, or discussion of any changed control technology, practice, or operations that could possibly explain how SWEPCO intends to achieve these lower limits.

Response

The basis for any changes in the emission rates is set forth in the July 28, 2008 submittal by SWEPCO. In it, the chosen technologies and emission limits are set forth.

That submittal did not contain revisions to previously submitted emission rate tables. The August 1, 2008 submittal updated these tables.

MACT Emission Limits

12. AEP's application fails to address sulfuric acid (H_2SO_4). The current draft permit includes a limit of 36 lb/hr, or 158 tons/yr, based on a "BACT" limit of 0.006 lb/MMBtu. This limit is neither BACT nor MACT.

Response

Sulfuric acid is not a Hazardous Air Pollutant as defined in the Clean Air Act. There is no MACT requirement for the pollutant. BACT for sulfuric acid was established in the draft permit. Subsequently this limit was lowered to 0.0042

lbs/MMBtu as BACT to coincide with the lowest permitted similar source after evaluating comments.

13. The MACT analysis is inadequate and flawed. The analysis does not consider the radioactive materials associated with the use of pulverized coal.

Response

The comments do not reference what radioactive material is in question. Radionuclides, a HAP, are contained in the PM_{10} surrogate analysis as described in this document.

Mercury

14. SWEPCO needs to provide the emission rate in terms of *lb/GWh* to compare to some of the rates. It is our understanding that they will translate to 15.6 lb/GWh which compares to the lowest rate of 15 lb/GWh. In addition, SWEPCO should demonstrate the need for the 1.7 limit as it relates to proven test results of less than 1 lb/TBtu.

Response

The limit does translate to 15.6 lbs/GWh based on plant ratings. The less than 1 lb/TBtu is derived from the MidAmerica test and preliminary reports of the Department of Energy (DOE) study. These are discussed further in subsequent comments and responses to mercury emission rates in this response to comments.

15. AEP suggests that long-term testing is required to establish a mercury MACT limit. However, this is inconsistent with AEP's MACT proposal for all other HAPS.

Response

This is based, partially on a former submittal. SWEPCO has proposed and ADEQ accepted a MACT limit based on the latest technology, Activated Carbon Injection (ACI). ACI is a relatively new technology with limited long term operational experience. A DOE long term study of ACI started in 2006.

16. The draft permit proposes a mercury emission limit of 1.7 lbs/TBtu (12-month average). This is not the "maximum achievable" limit, according to ADEQ's own analysis based on testing of other sources and permits.

    The MidAmerica plant has demonstrated compliance with their limit. The test result was 0.719 lbs/TBtu test average.

    A full-scale carbon injection system (TOXECON™) on a bituminous coal-fired boiler achieved over 99 percent mercury control a decade ago.

ADEQ claims that long term performance test data for activated carbon injection systems is unavailable and that Michigan Presque Isle has been achieving 90% reduction on a large term basis but no formal data could be obtained. SOB at 3. The subject Presque Isle data was reported at the 2007 Mega Symposium and in several McIlvaine Hot Topic Hour sessions. Further, at least two other full-scale, long term mercury control demonstrations have been reported to continuously achieve 90%+ mercury control --at Rocky Mountain Power in Montana and at Comanche Station in Colorado.

Response

ADEQ does not acknowledge that the stated levels have been "achieved" as defined in a MACT analysis. ADEQ presented the data for consideration in the analysis in determining the MACT emission rates.

The test data presented consists of one test at one facility that resulted in an average emission rate of 0.719 lbs/TBtu (MidAmerica) and one with an average of 2.25 lbs/TBtu (Springerville). To be considered the "maximum achievable", the limit must be achieved in practice. Achieved in practice is not the absolute lowest emission rate ever achieved by a source. It is the emission rate that a source can achieve on a continuous basis. Absent long term data, the permitted limits are the most appropriate standard of "maximum achieved".

The commenter provided not a report, but a copy of presentations for the Presque Isle (Toxecon/DOE project) facility, presumably made at the referenced symposium or other event. The provided information in no manner provides sufficient detail to evaluate long term performance or even emission rates. The final slide of one of the exhibits contains a bullet item stating that there are "still some significant issues to resolve".

The data for the Comanche plant (350 MW) is emission monitor data that indicates mercury emission rate far in excess of the proposed limit of 1.7 lb/TBtu for SWEPCO (on the order of 2 to 4 times higher). The monitor data may demonstrate long term availability and performance of the system; however it does not set a "beyond the floor" MACT limit less than the proposed SWEPCO limit of 1.7 lb/TBtu.

Likewise, information for the Hardin facility is in a presentation format and is not particularly useful. The information may state a 90% reduction, but outlet rates still appear, in the presentation slides, to be in the range of 3 lb/TBtu outlet range, again in excess of the SWEPCO proposal.

ADEQ agrees that ACI has been demonstrated as a viable technology. As indicated in the draft permit application, the Turk plant ACI will be designed similar to these other facilities. In setting an emission rate, 1.7 lbs/TBtu was determined to be the "maximum achievable" rate for sub-bituminous pulverized coal plant.

Volatile Organic Compounds

17. ADEQ acknowledges that actual test results for similar sources show that emissions of 0.000014 lb/MMBtu (Springerville) to 0.0022 lb/MMBtu(MidAmerica) have been achieved. Test results for Hawthorn Unit 5 in Missouri demonstrate that lower than the VOC emission limits than proposed as MACT have been achieved in practice at a similar source burning the same coal.

    There are probably a multitude of VOC test data, only three of which have been looked at here. SWEPCO should specifically address tested results versus the requested limit.

Response

ADEQ does not acknowledge that the stated levels have been "achieved" as defined in a MACT analysis. ADEQ presented the data for consideration in the analysis in determining the MACT emission rates.

However, the Hawthorn data does present actual data over a period of time, which is considered to have been achieved in practice. The additional Hawthorn test data presented for 5 years is:

Year	lb/MMBtu
2002	0.0005
2003	0.0002
2004	0.0003
2005	0.0004
2006	0.0005
Standard Deviation	0.00013
Mean	0.00038
Mean + 3 Standard Deviations	0.000771

The National Institute or Technology and Standards, NIST/SEMATECH Engineering Statistics Handbook, Chapter 6.3.2 sets forth the use of Shewhart Control Charts for variables. In this chapter, an upper range of process control is established as the mean plus three standard deviations.

Using the Hawthorn test data and the mean plus three standard deviations, ADEQ has determined that a limit of 0.00078 lbs/MMBtu (rounding up in the last digit) is demonstrated in practice by a similar source. This limit will be incorporated into the permit.

Other VOC facility test data representing a single data points are not deemed sufficient to determine any type of achieved emission rate for a particular source. Use of different tests on different sources would not be appropriate in establishing an achieved in practice rate for a source.

Hydrochloric Acid

18. The draft permit proposes a limit of 0.0006 lb/MMBtu for the acid gas HCl. Yet, ADEQ's analysis found that significantly lower HCl emissions are achievable based on test results (0.00003-0.00005 lb/MMBtu). Further, the U.S. Department of Energy measured HCl emissions from 16 different coal burning boilers, including with and without various control options, such as gas reburn, low NOx burners and selective noncatalytic reduction. This study demonstrated that several of the facilities emitted lesser amounts of HCl than proposed here: these include Boswell (0.00011 lb/MMBtu), Springerville (0.000176 lb/MMBtu), and Shawnee using lime injection with fabric filters (0.000073 lb/MMBtu).

Response

ADEQ does not acknowledge that the stated levels have been "achieved" as defined in a MACT analysis. ADEQ presented the data for consideration in the analysis in determining the MACT emission rates.

The commenter provides only three more data points consisting of test data to consider.

This test data presents ADEQ with a tested range of 0.00003 to 0.000176 lb/MMBtu to consider in determining MACT. Each of these tests represents a one hour sampling of emissions at a different facility. Though often the only available data and method of compliance possible, stack tests are a small "snap shot" of operations under carefully observed and controlled conditions. In order to set a rate solely based on test, it is necessary to evaluate what if any variation exists in the data. Ideally, multiple tests over a longer period with monitoring of operational conditions would establish this variability.

Test data representing a single data point is not deemed sufficient to determine any type of achieved emission rate for a particular source. Use of different tests on different sources would not be appropriate to establish an achieved in practice rate for a source.

Absent test data over a period of time for other sources, it is appropriate to consider permitted emission rates. Permitted similar sources established a floor of 0.0029 lbs/MMBtu. The 0.0006 lb/MMBtu beyond the floor limit is based on the lowest permitted source, Comanche (0.00064 lb/MMBtu).

Hydrogen Fluoride

19. SWEPCO is proposing a HF limit of 0.0002 lb/MMBtu. ADEQ's own analysis found that other facilities tested at significantly lower rates, from 0.00005 to 0.00014 lb/MMBtu. Other facilities not mentioned by ADEQ also have lower permitted levels of HF including the Thoroughbred Generating Station in Kentucky (0.000159 lb/MMBtu) and Longview Power in West Virginia (0.0000l lb/MMBtu). The U.S. Department of Energy measured HF emissions from 16 different coal burning boilers, including with and without various control options, such as gas reburn, low NOx burners and selective noncatalytic reduction. This study demonstrated that several of the facilities emitted lesser amounts of HF than proposed here as MACT including Springerville 0.000092 lb/MMBtu), Yates (0.000122 lb/MMBtu), Nelson Dewey (0.000067 lb/MMBtu), Burger using SNCR (0.000039 lb/MMBtu), and Shawnee using lime injection with fabric filters (0.000023 lb/MMBtu).

    ADEQ apparently did not consider beyond-the-floor control because none of the sources it found that reported control efficiencies has been tested. However, control efficiencies have been measured and reported. This information should be considered together with other data available from SWEPCO, including coal quality and scrubber design basis, to make a formal beyond the-floor determination.

Response

ADEQ does not acknowledge that the stated levels have been "achieved" as defined in a MACT analysis. ADEQ presented the data for consideration in the analysis in determining the MACT emission rates.

The commenter provides only five more data points consisting of test data to consider.

This test data presents ADEQ with a tested range of 0.000039 to 0.000159 lb/MMBtu to consider in determining MACT. Each of these tests represents a one hour sampling of emissions at a different facility. Though often the only available data and method of compliance possible, stack tests are a small "snap shot" of operations under carefully observed and controlled conditions. In order to set a rate solely based on test, it is necessary to evaluate what if any variation exists in the data. Ideally, multiple tests over a long period with monitoring of operational conditions would establish this variability.

Test data representing a single data point is are not deemed sufficient to determine any type of achieved emission rate for a particular source. Use of different tests on different sources would not be appropriate to establish an achieved in practice rate for a source.

Absent test data over a period of time for other sources, it is appropriate to consider permitted emission rates. Permitted similar sources established a floor of 0.0009lbs/MMBtu. The 0.0002 lb/MMBtu beyond the floor limit is based on the lowest permitted source, Weston (0.000217 lb/MMBtu)

ADEQ considered emission rates in this determination. The reported control efficiencies referenced in the comment would not yield any useful MACT limit due to the many variables involved (length and number of test, the broad ranges of efficiencies indicated, unknown test conditions, unknown coal constituents or variability, et als).

Lead

20. The draft permit proposes an emission limit of 0.000016 lb/MMBtu (3-hour average) for lead (Pb). There are probably a multitude of lead test data, only three of which have been looked at here. SWEPCO should specifically address tested results versus the requested limit. SWEPCO also needs to address the lower limits at the three plants, Sevier, Thoroughbred and AMP Ohio.

    ADEQ's own analysis indicates that lower limits are achievable. The Tuscon Springerville facility has a lead permit limit of 1.6 x 10-5 but tests conducted in 2006 show that the actual measured lead emissions were 0.029 to 0.038 x 10-5 lbs/MMBtu. Other tests are Holcomb (0.00000565 lb/MMBtu) and Stanton (0.00001 lb/MMBtu). The SOB assumes that lead would be controlled by the baghouse. However, lead and other metallic HAPs are present in the smallest particles which are not efficiently collected by baghouses. Thus, additional beyond-the-floor controls are required to meet MACT.

Response

ADEQ does not acknowledge that the stated levels have been "achieved" as defined in a MACT analysis. ADEQ presented the data for consideration in the analysis in determining the MACT emission rates.

The commenter provides only two more data points consisting of test data to consider. This test data presents ADEQ with a tested range of 0.00000029 to 0.00001 lb/MMBtu to consider in determining MACT. Each of these tests represents a one hour sampling of emissions at different facilities.

As with other pollutants, lead emission will be affected by the lead content of the coal and control equipment; lead will be controlled by the pollution control equipment to some extent. An evaluation of beyond the floor controls was conducted. There is no justification for the statement that additional controls are necessary to meet the MACT.

As explained in the application, permitted similar sources established a floor for lead of 2.6 x 10-5 lb/MMBtu. The 1.6 x 10-5 lb/MMBtu beyond the floor limit is based on the Springerville facility permitted limit.

Particulate Matter

21. ADEQ acknowledges that much more stringent limits even for PM_{10} have been achieved in practice and established by other permitting agencies -at least as low as 0.007 lb/MMBtu filterable, and 0.018 lbs/MMBtu total, according to the Statement of Basis. At least three years of stack test data (2005-2007) are available for the Hawthorne facility that demonstrate that a total PM_{10} limit of 0.018 lb/MMBtu has been achieved.

Response

ADEQ does not acknowledge that the stated levels have been "achieved" as defined in a MACT analysis. ADEQ presented the data for consideration in the analysis in determining the MACT emission rates.

The Hawthorn PM test data is as follows:

Year	Filterable	Total PM
2001	0.0118	0.016967
2002	0.010833	0.013367
2003	0.007767	0.011367
2004	0.010353	0.016633
2005	0.002	0.014
2006	0.002667	0.013
Standard Deviation	0.004275	0.002181
Mean	0.00757	0.014222
Mean + 3 Standard Deviations	0.020396	0.020764

The National Institute or Technology and Standards, NIST/SEMATECH Engineering Statistics Handbook, Chapter 6.3.2 sets forth the use of Shewhart Control Charts for variables. In this chapter, an upper range of process control is established as the mean plus three standard deviations.

Using the Hawthorn test data and the mean plus three standard deviations, ADEQ has determined that a limit of 0.021 lbs/MMBtu filterable is demonstrated in practice by a similar source. Since the SWEPCO proposed limit of 0.012 lb/MMBtu filterable is lower (based on permit limits) this limit will not be changed.

EPA recently issued NSR $PM_{2.5}$ rules. *See* 69 FR 28,331-28,350 ("Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)). In these rules, EPA adopted a transition period in which to conduct a test methods assessment for condensables in response to significant comment on the variability and reliability of existing test methods for measuring condensables. *Id.* At 28,334. The transition period will end January 1, 2011. "EPA will not require that States address condensable PM in establishing enforceable emissions limits for either PM_{10} or $PM_{2.5}$ in NSR permits until the completion of the transition period." *Id.* In that ruling, EPA encourages States to begin immediately identifying measures for reducing condensable PM emissions in major NSR permit actions, particularly where those emissions are expected to represent a significant portion of total PM emissions from a source. EPA states that if a State has developed the necessary tools to measure and control condensable PM emissions, then such States are not precluded from doing so in NSR permit actions. *Id.* at 28,335. However, PSD permits issued after the effective date of the rule, but during the transition period, are not required to account for condensable emissions in PM_{10} or $PM_{2.5}$ emissions limits. *Id.* at 28,334.

Therefore, ADEQ will not establish any MACT or BACT limit for these emissions. The permit will, however, retain a condensable limit, expressed as 0.025 lbs/MMBtu total PM_{10}, that is not part of BACT or MACT.

Other PM test data representing single data points are not deemed sufficient to determine any type of achieved emission rate for a particular source. Use of different tests on different sources would not be appropriate to establish an achieved in practice rate for a source.

Surrogates

22. AEP offers no evidence whatsoever that there is any relationship between total PM and the subject HAPs. Absent convincing data that there is a reliable relationship between these HAPs and total PM, ADEQ should establish separate limits for each HAP.

    AEP offers no evidence whatsoever that there is any relationship between total VOCs and the subject HAPs. Absent convincing data that there is a reliable relationship between these HAPs and total VOCs, ADEQ should establish separate limits for each organic HAP.

    AEP argues that the limitations and testing requirements for PM satisfy the MACT requirements for certain HAP compounds emitted as PM in the flue gases. MACT App., p. 10. The subject compounds are listed in Table 1 of the MACT analysis. This one paragraph argument does not satisfy MACT for the so-called "HAPs included in total PM."

Response

A permitting authority may use a surrogate to regulate HAPs if it is reasonable. *National Lime Ass'n v. EPA*, 233 F.3d 625, 639 (D.C.Cir.2000) (MACT standards for portland cement manufacturing facilities) (citing *Dithiocarbamate Task Force v. EPA*, 98 F.3d 1394, 1399 (D.C. Cir. 1996) (EPA may attribute characteristics of a subclass of substances to an entire class of substances if doing so is scientifically reasonable); *NRDC v. EPA*, 822 F.2d 104, 125 (EPA may regulate pollutant indirectly when its emissions are controllable by regulation of other pollutants).

Use of PM as a surrogate for certain HAPs is reasonable if: (1) the HAPs are invariably present in PM; (2) the PM control technology indiscriminately captures those HAPs along with other particulates; and (3) PM control is the only means by which facilities can achieve reductions in these HAP emissions. *National Lime Ass'n v. EPA*, 233 F.3d at 639.

In support of its regulation, EPA demonstrated that there was a correlation between HAP metals and PM, and that the PM control technology would carry some quantum of HAP metals with each unit of PM emissions avoided. *Id.* At 639. In other words, "where there is cement kiln PM, HAP metals are always in it, and when cement kiln PM is removed from emissions, HAP metals are always removed with it." The court held that this was reasonable even though EPA conceded that the ratio of HAP metals to total particulates was very small.

In 2007, the Seventh Circuit elaborated the reasonableness of using PM as a surrogate for HAPs, stating:

> **PM might not be an appropriate surrogate for HAP metals if switching fuels would decrease HAP metal emissions without causing a corresponding reduction in total PM emissions. [] The reason is clear: if EPA looks only to PM, but HAPs are reduced by altering inputs in a way that does not reduce PM, the best achieving sources, and what they can achieve with respect to HAPs, might not be properly identified.**

Sierra Club v. E.P.A, 353 F.3d 976 (D.C.Cir. 2004).

In this case, the Department determined that the source category was pulverized coal plants burning sub-bituminous coal with a capacity similar to the proposed 600 MW Turk plant. Fuel switching to natural gas, nuclear, or even among the different types of coal was not considered in the MACT analysis because such sources are not considered similar in design and, therefore, are not similar sources.

The conditions that allow particulate HAPs to be a surrogate at Portland Cement Kilns is the same that would allow the use of surrogates at the SWEPCO facility.

Both Portland cement kilns and the Turk plant will have similar emissions, not considering the different air pollution control trains, when they combust coal. The HAPs listed in the application as contained in the PM surrogate are invariably present in PM; (2) the PM control technology indiscriminately captures these HAPs along with other particulates; and (3) PM control is the only means by which the facilities can achieve reductions in these HAP emissions.

The VOC surrogate argument parallels this PM argument. Organic HAPs will always be found in the VOC, there will always be organic HAPs controlled through good combustion practices, and there are no other, better controls to consider for organic HAPs.

23. AEP's list of HAPs included in total PM two HAPs that are volatile and would be emitted as gases –selenium and cyanide.

Response

At the control equipment (fabric filter) temperature, a portion of selenium would be in the particulate and the gas phase. Cyanide would react with lime in the scrubber to form calcium cyanide particles and collected in the fabric filter. In that there are no other, better controls available for these compounds and they are invariably found in the PM_{10} and some portion are removed with the PM_{10}, the use of PM_{10} as a surrogate is acceptable.

24. The same types and levels of PM control cannot simultaneously satisfy BACT and MACT due to different physical characteristics of the subject particles. Total PM includes all sizes of particles. The total PM HAPs, on the other hand, are present in very small particles. These very small particles are much more difficult to collect than the larger particles making up the bulk of total PM.

Response

There is no control technology specific to very small particles that are required as a result of the MACT evaluation. The fabric filter is the best MACT technology for particulate in general. Therefore, the same controls can satisfy both BACT and MACT requirements.

25. AEP assumes that all of the total VOC HAPs result directly from the combustion of coal and that combustion controls therefore adequately control them. It is long established that this is not true. Numerous studies, for example, have failed to identify mechanisms that control the formation of dioxins. Combustion controls do not control dioxins, which are present in part as condensed particulate matter and thus better controlled by filtration media with high removal efficiency for submicron particles. Further, high concentrations of these VOC HAPs have been detected from facilities with good combustion controls.

The assumption that BACT for VOCs satisfies MACT for certain nonvolatile organic HAPs is incorrect

Response

That the mechanism of their formation may not be well understood is not necessarily relevant in the MACT determinations. There are no additional MACT controls specific to these compounds. Use of a surrogate is permissible if: 1) the HAP are invariably present in the surrogate (2) the surrogate control technology indiscriminately captures HAP along with other components of the surrogate; and (3) surrogate control is the only means by which facilities can achieve reductions in HAP emissions. *National Lime Ass'n v. EPA*, 233 F.3d at 639. The surrogate limit is then set to reflect MACT levels.

26. Any grouping scheme should consider the physical and/or chemical properties of compounds and their behavior under combustion conditions and in the air pollution control train -and, hopefully, only group those compounds that exhibit similar or reasonably similar behavior in coal combustion.

Response

This is not necessary. Use of a surrogate is permissible if: 1) the HAP are invariably present in the surrogate (2) the surrogate control technology indiscriminately captures HAP along with other components of the surrogate; and (3) surrogate control is the only means by which facilities can achieve reductions in HAP emissions. *National Lime Ass'n v. EPA*, 233 F.3d at 639. The surrogate limit is then set to reflect MACT levels.

27. The draft permit proposes VOC as the surrogate for an unspecified group of volatile organic HAPs, and proposes a limit of 0.0025 lb/MMBtu (3-hour average). The application and draft permit fail to explain why VOC is an appropriate surrogate.

    There are three classes of organic HAPs that must be considered in setting MACT limits. These are: (1) volatile organic compounds, which are gases; (2) semi-volatile organic compounds, which may be gases or solids, depending on where in the exhaust gas train they are; and (3) particulate organic compounds, such as polynuclear aromatic compounds and dioxins, which are present in the particulate fraction. These three classes behave differently during combustion. A single indicator, VOC, which primarily measures only the first class (gases), cannot be used as a surrogate for these three diverse groups of chemicals as they are chemically and physically dissimilar.

    Compliance is demonstrated using EPA Method 25A. This method measures only volatile organic compounds and not nonvolatile organic compounds, such as dioxins. All organic HAPs must be regulated, not just the volatile HAPs. There is adequate stack test data to establish a MACT limit for dioxins. *See,* Exhibits 4, 5, and 29.

Response

Components included in the VOC surrogate are listed in the application on ADEQ emission rate tables. Use of a surrogate is permissible if: 1) the HAP are invariably present in the surrogate (2) the surrogate control technology indiscriminately captures HAP along with other components of the surrogate; and (3) surrogate control is the only means by which facilities can achieve reductions in HAP emissions. *National Lime Ass'n v. EPA*, 233 F.3d at 639. The surrogate limit is then set to reflect MACT levels.

Whether volatile, semi volatile or particulate, these conditions for use of VOC as a surrogate are met.

28. Components in the PM_{10} Group. ADEQ does not disclose which HAPS are included in the "among others." Further, cyanide is not a metal, but rather a volatile gas that is not included in VOCs, PM_{10}, or any other HAP category. Thus, ADEQ has failed to set a MACT limit for the highly toxic chemical cyanide.

Response

Appendix A of the application specifically lists all the HAPs, emission rates, and which surrogate, if any, they are contained in. Cyanide would react with lime in the scrubber to form calcium cyanide particles and would be collected in the fabric filter. In that there are no other, better controls available for these compounds and they are invariably found in the PM_{10} and some portion are removed with the PM_{10}, the use of PM_{10} as a surrogate is acceptable.

29. Particulate matter is not an adequate surrogate for all metallic HAP because all metallic HAP are not invariably present in particulate matter. All of these elements are not consistently present in particulate matter at the inlet to the particulate control device. Some are present as gases.

    Particulate control does not indiscriminately capture HAP metals. Most metallic HAPs are volatilized in the boiler and condense as very fine particulate matter or nanoparticles (typically smaller than 1 micron) in the pollution control train. The highest concentrations of most metallic HAPs are consistently found in the smallest particles. These very tiny particles are not captured in control devices with the same efficiency as the larger particles.

Response

The commenter makes arguments that mirror the court decision on surrogates referenced in previous responses.

That the surrogate control may not control all or even a large portion of the HAPs metals, does not make it improper. It is proper if the HAP is invariably present in the surrogate, if the surrogate control indiscriminately removes the HAP, and if there is no other, better control available for the HAP.

HAP metals are invariably in particulate matter. At the temperatures of the baghouse, some fraction of the HAPs will be particulate. Invariably, in this case does not mean that all HAPS will be in the same fraction or amount; it only means that they *will* be present. Indiscriminately means that with the surrogate removal, there will always be some removal of the HAP. Lastly, there is no other, better control available for removal of these HAPs.

30. Finally, mercury controls, including powdered activated carbon proposed to control mercury emissions have been demonstrated to increase the amount of chromium and nickel in stack gases, compared to no mercury control.

Response

The one slide of a presentation lacks any meaningful or useful information. The data suggests an increase but offers no details as to the reason why, the conditions of the test or the repeatability of the test. In a subsequent slide, the data presented still indicates high removal efficiencies (95%+ for Nickel, 94%+ for chromium) using ACI, based on coal metal constituents.

The information presented does not present any data or give ADEQ pause to consider that additional controls would be required based on these suggested increases in nickel and chromium.

31. If particulate matter is used as a surrogate for any non-mercury metallic HAP, it should be based on the smallest size fraction feasible. Methods have been developed to measure particulate matter smaller than 2.5 microns or $PM_{2.5}$, which is a better surrogate for metallic HAPs than PM or PM_{10}.

Response

There is no information to establish such a limit or information that such a limit would provide any better control or monitoring of particulate HAPs. A PM_{10} limit is sufficient.

32. A MACT analysis for lead and other non-volatile HAPs must consider methods to enhance the removal of finer particles. Methods to enhance the control of fine particles include:
    - Use of a filtration media with a higher removal efficiency (99.99%) for nanoparticles (examples are included in the table found at Appendix B) and bag leak detection system;
    - Use of a wet electrostatic precipitator (Exh. 26); and

- Use of an agglomerator upstream of the baghouse.

Response

Advanced filter media was addressed in Appendix A, page 50 of the application. In that section, it is explained that nano-technology is a still in the research phase.

The filtration media to which the commenter refers in the appendix will be used by the Turk plant. *See* Page 17 of SWEPCO's Responses to Comments on ADEQ's 112(g) Draft Permit Decision for the John W. Turk, Jr. Power Plant, AFIN: 29-00506 October 8, 2008.

> ***The fabric filter media utilized in the Turk baghouse will be polyphenylene sulfide (PPS) with a PTFE coating. This is equivalent to the 6282 material produced by Donaldson Company, Inc. that is listed in the table contained in Appendix C of the EIP comments.***

SWEPCO also explains the use of that particular media versus one other media with a higher reported efficiency. The other media is sensitive to high alkalinity as found in the Turk facility's exhaust.

40 CFR 63 Subpart EEE—National Emission Standards for Hazardous Air Pollutants from Hazardous Waste Combustors requires either a bag leak detector or a particulate monitor. Subpart LLL—National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry contain an option for use of bag leak detection. Bag leak detectectors are an available technology and the requirement for a bag leak detector for Turk will be consistent with these monitoring requirements. A bag leak detector will be added to the permit requirements.

Agglomerators were addressed in Appendix A, page 50 of the application. The exhibits provided do not provide any useful data that an agglomerator would affect particulate emissions at the Turk plant. The test data in the provided material that can be used indicates that the facility with an agglomerator will have emission rates at or above the Turk facility's permitted particulate rate of 0.025 lbs/MMBtu. The test data in the provided documentation also indicates it is based on Method 17 test data that would not include condensibles. Inclusion of condensibles would increase the agglomerate test data emission rates more.

SWEPCO evaluated a wet ESP in Appendix A starting on page 49. The information provided by the commenter did not have any data that would indicate a wet ESP is better control than a fabric filter.

In a DOE document on the matter of fabric filters (http://www.netl.doe.gov/technologies/coalpower/ewr/pm_emissions_control/con_tech/hybrid.html)

...Fabric filters are currently considered to be the best available control technology for fine particles, but emissions are dependent on ash properties and typically increase if the air-to-cloth (A/C) ratio is increased.

33. There is lack of a meaningful particulate matter limit to control metals and non-volatile HAPs. Assuming *arguendo* that particulate matter is an appropriate surrogate for these HAPs, the limit must be tightened and expressed as a $PM_{2.5}$ limit, and not a PM_{10} limit. The chosen filterable and total PM_{10} limits are no different from the limits proposed in the previously issued draft permit, which included no MACT analysis.

Response

There is no evidence that a $PM_{2.5}$ limit would result in lower HAP emission rates or different control measures. Further, there is no data to evaluate or set such a standard. That the MACT and BACT emission rates are identical is irrelevant.

MACT Analysis

34. Some HAPs were not considered. EPA's report to Congress lists HAPs that are not included in the SWEPCO Turk MACT analysis. For example, radionuclides are HAPs that are not considered.

Response

Radionuclide would consist of particulate matter and be covered in the PM_{10} surrogate.

35. **SWEPCO should have considered a wide range of alternatives as part of its MACT analysis.**

The Clean Air Act's HAPs provisions are designed to compel applicants to use every tool at their disposal to (a) match the emissions levels achieved by the best controlled similar source, and (b) exceed that level of achievement where possible. As the implementing regulations for the HAPs provisions specify, an applicant must look to all "measures, processes, methods, systems or techniques to limit the emission of hazardous air pollutants through process changes, substitution of materials, or other modifications." 40 CFR 63.40 (definition of "control technology.").

SWEPCO should have engaged in precisely this sort of search to determine if it could achieve reductions beyond the floor -beyond the level achieved by the "best controlled similar source." Because it engaged in no such analysis *at all,* there is not even a "beyond-the-floor" analysis to critique There are, however, some alternatives that ADEQ must be aware of that, if implemented, would achieve further reductions. These include:

- Switching from coal to natural gas,
- Use of high-rank coals,
- Selective mining of coal,
- Coal washing,
- Considering Integrated Gasification Combined Cycle (IGCC) as an alternate combustion method.

Response

The EPA has defined a "similar source" as "a stationary source or process that has comparable emissions and *is structurally similar in design and capacity* to a constructed or reconstructed major source such that the source could be controlled using the same control technology." 40 C.F.R. 63.41. In determining the MACT floor, ADEQ must consider sources that are structurally similar in design and capacity. The Department did not consider switching from coal to natural gas, use of a different type of coal, or use of IGCC as an alternative combustion method in the MACT floor determination because none of these options are structurally similar to a sub-bituminous PC power plant.

The commenter references a USGS Fact Sheet FS-095-01, September 2001, for the basis of the alternatives (with the exception of the IGCC comment). Post-combustion removal of mercury from the power plant stack emissions is another option listed in the fact sheet that the commenter omitted.

The fact sheet is merely descriptive of measures that might be further explored to reduce mercury emissions. It lends no qualitative or quantitative weight to any of the options. The document indicates it is part of an early coal evaluation of reduction investigations for coal. There is insufficient evidence on which to evaluate coal washing or selective mining scenarios.

It should be noted that PRB coal has the second lowest reported mercury content of US coals in the table contained in the fact sheet.

36. Packed beds of sorbent material, typically carbon, have been used in Japan and Germany to remove mercury, dioxins, and other HAPs from a wide range of combustion sources, including coal-fired power plants. ReACT has been installed on 14 commercial units to date, including 4 coal-fired utility boilers. These are in Japan and Europe. The technology has been in operation at the 350 MW Takehara Unit 2 since 1995 and the 600 MW Isogo Unit 1 since 2002. A 600 MW unit is currently under construction at Isogo Unit 2. Isogo Unit 1 has achieved greater than 98% SO2 removal, 10-50% NOx removal, greater than 95% particulate removal, and greater than 90% mercury removal. "Commercial installations located in Japan and Germany operate at 90-99% SO2 removal, with SO2 inlet concentrations as high as 1300 ppm SO2.

Response

The ReACT process is currently undergoing a trial in a 2.5 MW slipstream at the North Valmy Station. The results do indicate a possible high level of removal for mercury. However, results in the documentation stated a 90% mercury removal which is the same (or lower) as that reported in activated carbon injection.

37. The additive, TMT, is used on virtually all coal-fired power plants in Germany to control the mercury content of scrubber waters. It has the added benefit of achieving 90 percent control of mercury emissions from the stack.

Response

Information in a DOE presentation (www.netl.doe.gov/publications/proceedings/06/mercury/presentations/Blythe_presentation_Field_121206.pdf) indicates that TMT is an additive to affect mercury "re-emissions" in wet scrubbers. In other words, it is used to minimize mercury emissions that result from re-circulated water in scrubbers. The Turk plant will not have such re-circulating wet scrubbers.

Compliance and Monitoring

38. Maximum achievable limits must include the most stringent averaging periods for all regulated pollutants. In addition, for compliance purposes, monitoring and testing requirements must assure compliance with the most stringent applicable (i.e., short term) averaging periods.

Response

MACT does not preclude the use of long term averaging times when justified. The comment is noted.

39. The Clean Air Act and Arkansas law require permits to contain terms and conditions that assure compliance with the applicable limits. For lead, PM_{10}, HCl, HF, VOC, and CO, the draft permit requires only an annual stack test (only an initial test for the auxiliary boiler). This is insufficient to verify that MACT limits are being met. A once a-year test is insufficient to assure compliance, and continuous emissions monitoring systems are widely available and in use today.

    ADEQ should require continuous emissions monitoring systems (CEMS) for fine particles (as PM 2.5, or a select group of speciated non-volatile HAPs), HCl, HF, and VOCs for the main boiler (SN-01) and for PM and CO for the auxiliary boiler (SN-02).

Response

Continuous emission monitors are not a requirement for all pollutants. The main boiler will have a CO continuous emission monitor. HCl and HF emissions are, in part, a function of the control equipment which has a continuous monitor for SO_2 assuring consistent operation of the equipment.

Particulate monitors are not well established. PM monitors are not required by any EPA rules, they are either suggested as in the Boiler NSPS or specifically discounted as in the Hazardous Waste Incinerator rules, 40 CFR 63.1209(a)(1)(iii).

The main boiler has a CO continuous emission monitor. PM and CO monitoring for the auxiliary boiler is excessive based on the level of emissions and limited operations

Annual testing is sufficient for these pollutants and similar to other state and EPA determinations.

40. Continuous emissions monitoring systems (CEMS) are the preferred method for determining compliance with PM limits. 40 CFR §§ 60.42, *et seq.* American Electric Power has agreed to install PM CEMS on some of its existing coal plants. The EPA has strongly urged PM CEMs, and determined that PM CEMS are reliable and accurate. There are many facilities that operate PM CEMS and have demonstrated that the systems are reliable and accurate. These include Tampa Electric power plant (Florida), Eli Lilly Corporation (Indiana), and the U.S. Department of Energy (Tennessee). EPA has also secured commitments from up to 30 existing coal-fired utility installations to install PM CEMS over the next couple of years.

Response

The use of particulate monitors is a case by case evaluation. EPA prefers but does not require their use. Particulate CEMs are further elaborated on in previous comments and responses.

41. MACT are utilized in order to assure that an area maintains attainment. It is clear that this plant will utilize technologies to reduce emissions. However, without the implementation of a more stringent monitoring plan, the current permit does not provide significant evidence that the control technologies will function properly. Accurately insuring that the emissions of the plant are within this permit's limitations requires more monitoring of the emissions. Sampling a stack once per year for three hours to calculate annual emissions is not sufficient to evaluate if the MACT are functioning properly or if the permittee is in compliance with its permit.

Response

MACT requirements are not directly related to attainment issues. Attainment issues are related to criteria pollutants, MACT is related to hazardous air pollutants. There is some overlap in the use of VOC and PM_{10} as surrogates in the MACT analysis.

Attainment issues were addressed in the PSD/NSR Title V draft decision. In that, the ambient air impact of the various criteria pollutants and monitoring were addressed. Depending upon the pollutants, continuous emission monitors (for SO_2, NO_x and CO) were required or annual testing (VOC, PM_{10}) was required.

For the MACT pollutants, Mercury will require a continuous monitor and the other pollutants annual testing. Additionally, CO monitors, SO_2 monitors and bag leak detectors provide monitoring of boiler operation and control equipment, and therefore indirectly, pollutant monitoring.

Public Notices

42. As a related matter, we urge ADEQ to re-issue the public notice and Draft Operating Permit, once the agency has finally concluded its technical review, including the MACT analysis. The Public Notice for Draft Permit and Public Hearing, dated June 12, 2007, was deficient as a matter of law. First, it failed to include a MACT determination. Second, the agency's technical review of the application was *ongoing* during the public comment period. In fact, the applicant submitted modeling which ADEQ then considered as part of the application process. Thus, we are not requesting a "second" public notice period, as some have suggested, but simply urging ADEQ to issue a legally sufficient first notice.

    The public is entitled to review and comment on a complete application and draft permit. However, the June 2007, public notice was incomplete and inaccurate, and therefore fails to comply with Arkansas and federal law. The remedy is to issue a public notice and draft permit *after* ADEQ has completed its review and issued a draft permit that complies with all applicable requirements.

Response

The procedures for issuing draft permitting decisions are set forth in APC&EC Regulation 8.2.1 *et seq.* Regulation 8 requires the Director to publish notice of a proposed draft permitting decision and provide: (1) the name and telephone number of the division of the Department responsible for the draft permitting decision; (2) the name and business address of the permittee; (3) the type of action for which the permitting decision is proposed to be issued; (4) the date of the issuance of the draft permitting decision; (5) a brief summary of the draft permitting decision; (6) a statement that the draft permitting decision is available for copying at the Department; and (7) a statement that the submission of written

comments by any person will be accepted by the Department during the public comment period.

During the public comment period, persons are permitted to copy or inspect the draft permitting decision and other material relevant thereto and submit written comments, data, view or arguments on the draft permitting decision. Those persons that submit public comments are given standing to appeal final permitting decisions made by the Department.

SWEPCO submitted an application to ADEQ for a Title V air permit to operate the Turk Plant on August 8, 2006. The Department determined that SWEPCO's application met the requirements of APC&EC Regulations 8 and 26 and a proposed draft permitting decision was issued on June 12, 2007. The deadline for public comments was extended twice. Written comments were accepted until the close of business on August 6, 2007.

Commenters have asserted that ADEQ should not have issued a proposed draft permitting decision until after it reviewed all air modeling data and completed the technical review of the permit application. ADEQ disagrees. The issuance of a proposed draft permitting decision did not foreclose the Department from considering information after the proposed draft permitting decision was published. Reg. 26.407 specifically provides as follows: "If while processing an application that has been determined or deemed to be complete, the Department determines additional information is necessary to evaluate or take final action on that application, it may request such information in writing..." Similarly, the applicant is under a duty to update incorrect information and supplement any relevant facts that may have been omitted. Reg. 26.409. Arkansas law does not require ADEQ to provide notice and a comment period on everything that it reviews after it issues a draft permitting decision. If ADEQ could not change the conditions of a permit after receiving comments or additional information, it would be placed in the position of either being unable to learn from the comments and information or being forced to commence new comment periods *ad infinitum.*

Although commenters have suggested that ADEQ should have started the review process over and issue a new draft permitting decision, ADEQ's consideration of additional information after the close of the public comment period has not interfered with the commenters' right to raise any legal and factual objections that have been raised in the public comments or to those that could not have been discovered and raised during the public comment period. Ark. Code Ann. § 8-4-205(b)(2).

Also, there would have been a significant impact on the public had ADEQ re-issued the proposed permitting decision in one document as requested by commenters. If ADEQ issued a subsequent single proposed permitting decision, all those persons that had submitted previous comments would have had to submit new comments.

43. The June 12, 2007, Public Notice is Deficient as a Matter of Law.

It is our understanding that ADEQ intends to make a MACT determination and limit public notice and comment opportunity to the MACT analysis. However, a piecemeal approach to the preconstruction/operating air permit for this new source (i.e., separating out the MACT component for purposes of agency review and public notice) is impractical, inefficient, and legal error.

Response

On February 8, 2008, the U.S. Court of Appeals for the D.C. District vacated the U.S. EPA's Clean Air Mercury Rule (CAMR) which established a mercury cap-and-trade program for new and existing electric generating units (EGUs) and allocated mercury allowances to states. (*State of New Jersey, et al. v. EPA*, 517 F. 3d 574 D.C. Cir. 2008) The court decision eliminated EPA's cap-and-trade approach to regulating mercury emissions and, consequently, required Arkansas and other states with federally delegated Title V programs to make a case-by-case determination that the permit applicant will meet Maximum Achievable Control Technology (MACT) standards. The federal requirements for a case-by-case MACT determination are contained in 40 CFR 63.43.

As a result of the vacatur of the CAMR rule, SWEPCO submitted a MACT application for the Turk plant as required by CAA Section 112(g) which has been subject to public notice and public comment under Arkansas' duly-approved preconstruction permit program.

Commenters contend that ADEQ should have re-issued the entire proposed draft permitting decision after ADEQ received the MACT submittal. ADEQ disagrees. SWEPCO's original application was not deficient for failing to contain a case-by-case MACT analysis. Until the D.C. Circuit Court of Appeals vacatur of the CAMR rule, there was no requirement for a MACT analysis.

ADEQ was required to review and approve, or disapprove the MACT application, and provide public notice and an opportunity to comment on the MACT determination. ADEQ has met those requirements. The public was afforded the opportunity to raise all legal and factual objections to the MACT analysis in a separate public comment period. Commenters have been afforded the opportunity to comment on all aspects of the permit application and submittals even though their comments were accepted during two different public comment periods. Further, EPA regulations regarding case-by-case MACT determinations contemplate that a MACT determination can be considered in a separate review and Regulation 26.409 provides for the submission of additional information necessary to address any requirements that become applicable after filing a complete application, as occurred here.

Also, there would have been a significant impact on the public had ADEQ re-issued the proposed permitting decision in one document as requested by commenters. If ADEQ issued a subsequent single proposed permitting decision, all those persons that had submitted previous comments would have had to submit new comments.

44. The fact that new modeling was submitted by the applicant and considered by ADEQ *after* the initial 2007 public notice, is yet another reason to provide the public a meaningful opportunity to comment on a single, complete draft permit, after ADEQ finishes its technical review. This error, alone (even without the new MACT submittal) requires remedial action in the form of a new public notice. A new public notice would not be a "second" notice, but rather, it would be the *first* legally sufficient notice.

Response

ADEQ provided public notice and an opportunity to comment on SWEPCO's original application and ADEQ's proposed draft permitting decision. When additional information was required to be considered, the case-by-case MACT analysis, ADEQ provided public notice and an opportunity to comment on the MACT determination. ADEQ is not required to re-notice the original application and the additional information in one document and start the comment period over.

45. Assuming, for the sake of argument, that re-noticing could be considered a "second" public notice, instead of a sufficient first notice, there is no prohibition anywhere in Arkansas law against this. The time limit for final action on a permit application, in Regulation 26.502, is no excuse to disregard the legal requirements for public notice. In addition, even under the Reg. 26.502 (I8-month) time limit, the clock starts on April 9, 2008, the date on which AEP submitted the MACT supplement to its application. As further explained below, neither Arkansas nor federal law contemplates piecemeal, separate, applications and determinations for a new source such as the Turk plant; MACT is simply a required (and critical) component of an Arkansas preconstruction Operating Permit. Eighteen months from the April 2008 supplement to public notice of a draft permit is ample time for ADEQ to complete its review and issue a draft permit and public notice.

The April 9, 2008, MACT submittal provides yet another justification for a new public notice for this draft: permit. The federal requirements for a case-by-case MACT determination are contained in 40 CFR 63.43. ADEQ must review and approve, or disapprove, a MACT application, and provide public notice and an opportunity to comment on the MACT determination, pursuant to its approved Title V/Operating Permit program rules. These requirements have not been met.

Response

See responses above. ADEQ provided public notice and an opportunity to comment on SWEPCO's original application and ADEQ's proposed draft permitting decision. When additional information was required to be considered, the case-by-case MACT analysis, ADEQ provided public notice and an opportunity to comment on the MACT determination. ADEQ is not required to re-notice the original application and the additional information in one document and start the comment period over.

Also, there would have been a significant impact on the public had ADEQ re-issued the proposed permitting decision in one document as requested by commenters. If ADEQ issued a subsequent single proposed permitting decision, all those persons that had submitted previous comments would have had to submit new comments.

46. AEP is required to obtain from ADEQ an approved MACT determination. 40 CFR 63.43(b). Because the Arkansas preconstruction permitting is a combined PSD/Title V (Operating) permit, there is only one review option available. 40 CFR 63.43(c)(1)

Response

Regulation 19 requires Arkansas to issue a single air permit for stationary sources which contains federally enforceable and state enforceable provisions. The public was afforded the opportunity to comment on the information that was in the record and ADEQ's draft permitting decision as required by Regulation 19.406. When additional information was required to be considered, the MACT analysis, the public was afforded the opportunity to raise all legal and factual objections to the MACT analysis in a separate public comment period. Regulation 26.409 provides for the submission of additional information necessary to address any requirements that become applicable after filing a complete application, as occurred here.

As required by Regulation 19, the final permit is a single permit that includes all emissions limitations and standards applicable at the time of issuance, including those governing hazardous air pollutants.

47. For these reasons my clients are opposed to the issuance of the 112(g) permit for the Turk facility. This permit should be reviewed and additional analysis supplied to ensure that the Maximum Achievable Control Technologies are employed. SWEPCO should be required to complete its permit application in compliance with all applicable laws and regulations, and a new 30 day comment period should commence after completion of those requirements.

Response

SWEPCO has submitted a permit application and MACT analysis that complies with all applicable laws and regulations. ADEQ provided public notice and an opportunity to comment on SWEPCO's original application and ADEQ's proposed draft permitting decision. When additional information was required to be

considered, the case-by-case MACT analysis, ADEQ provided public notice and an opportunity to comment on the MACT determination. ADEQ is not required to re-notice the original application and the additional information in one document and start the comment period over.

Also, there would have been a significant impact on the public had ADEQ re-issued the proposed permitting decision in one document as requested by commenters. If ADEQ issued a subsequent single proposed permitting decision, all those persons that had submitted previous comments would have had to submit new comments.

Other MACT Comments

48. We disagree with AEP's legal contentions regarding the significance of the recent D.C. Circuit decision vacating CAMR and the de-listing of coal fired EGUs. However, we agree with AEP that the recent court decision clearly does have a practical impact on the proposed plant. And, as AEP seems to implicitly acknowledge by filing a MACT application, there is no straight-faced argument that a case-by-case MACT determination is not required.

    Further, AEP's suggestion that forthcoming EPA guidance might have any bearing on this matter, is wrong. The federal Clean Air Act is clear: a case-by-case MACT application must be submitted, and a determination must be made. Because EPA has not promulgated categorical MACT standards applicable industry-wide, a case-by-case determination pursuant to CAA Section 112(g) is required. 42 U.S.C. § 7412(g); See also, 40 C.F.R. §63.40(c)

Response

ADEQ agrees that a case-by-case MACT pursuant to CAA Section 112(g) is required and a determination thereupon has been made.

49. There is no dispute that Turk would be a major source under Section 112. There is irrefutable evidence that construction has begun on the plant; the amount of activity on the site could constitute nothing less than "construction."

Response

ADEQ agrees that the Turk plant will be a major source pursuant to CAA Section 112. With respect to whether construction has begun, the commenter has failed to specify the evidentiary basis for the comment.

50. The application and draft 112(g) permit are deficient for numerous reasons. The application, draft permit, and ADEQ's review and analysis of the proposed project, failed to comply with the requirements of the Federal Clean Air Act (42 U.S.C.

§§7401 at *et seq.).* The Application, draft permit, and ADEQ review fail to comply with the requirements of the statutes and regulations regarding the analysis required for hazardous air pollutants ("HAPs") impacts from the proposed plant. Primarily, the misconception of the necessary approach to the MACT analysis required by the regulations, and the reliance of ADEQ on the insufficient analysis performed by SWEPCO, renders the Permit legally improper.

Response

The comment has not specified with which requirements were not complied. The Department conducted a proper and legally sufficient 112(g) analysis. The Department not only reviewed the MACT application and analysis submitted by SWEPCO but conducted an independent analysis.

51. The MACT analysis must begin with a review of the lowest emission limit that has been proven.

Response

The ADEQ does not disagree with the comment. No specifics were stated.

52. 40 C.F.R. § 63.43(e)(2)(xi)-(xiii). This section indicates that the technology review process begins by establishing the maximum achievable emission limitation and then determining the technology that needs to be employed to achieve that limit. In this instance, SWEPCO, as further discussed below, has determined the lowest emissions rate for the technologies it has previously chosen. By limiting its analysis, SWEPCO fails to include "...alternative control technologies considered by the applicant." SWEPCO's abject failure to consider alternative control technologies to its preferred ultrasupercritical pulverized coal alternative is a fatal flaw that permeates its permit application generally and its MACT and BACT analysis in particular. This analysis is contrary to the plain language of the statute and regulations and does not further the goal of consistently lowering the emissions rates of HAPs. To accept such analysis allows companies to pick a cheaper technology with less stringent permitted emissions limits. It is important to remember that the overarching goal of the Act is to consistently improve technology and create a means by which the greatest pollutant reducing technologies are employed to progressively decrease emissions.

Response

The commenter states that the technology review was improper and cites to 40 C.F.R. § 63.43(e)(2)(xi)-(xiii). That regulation provides:

> **(e) Application requirements for a case-by-case MACT determination.**
>
> ...

(2) In each instance where a constructed or reconstructed major source *would require additional control technology or a change in control technology*, the application for a MACT determination shall contain the following information:

...

(xi) The selected control technology to meet the recommended MACT emission limitation, including technical information on the design, operation, size, estimated control efficiency of the control technology (and the manufacturer's name, address, telephone number, and relevant specifications and drawings, if requested by the permitting authority);

(xii) Supporting documentation including identification of alternative control technologies considered by the applicant to meet the emission limitation, and analysis of cost and non-air quality health environmental impacts or energy requirements for the selected control technology; and

(xiii) Any other relevant information required pursuant to subpart A.

***Id.* (emphasis added).**

This regulation addresses what is required where a major source would require additional control technology or a change in control technology in order to achieve the required emissions reductions required by the MACT floor.

The proposed plant was evaluated with all the controls necessary to meet the MACT limits in the PSD/NSR permit. The MACT 112(g) permit did not require any additional controls that were not already considered. Activated Carbon Injection may not have been clearly indicated in the PSD/NSR permit. Information on ACI was included in the 112(g) application in the August 1, 2008 supplemental information letter.

53. SWEPCO states, with reference to their application, that the "maximum achievable emission rates identified represent rates that are ... among the most stringent in the United States for a sub-bituminous PC unit." Application p. 13. Unfortunately, SWEPCO's 112(g) case-by-case MACT analysis is incomplete and was improperly undertaken. Under the MACT regulations an applicant must look at the lowest *achievable* source limitation. Therefore, the analysis has to look beyond the permit limits of existing plants to the actual reported emissions. Simply reviewing materials from permit applications is insufficient; the applicant must actually evaluate the results of testing and operation of its preferred alternative as well as other alternative control technologies to determine the lowest achievable limit. Achieved in practice does not imply that you perform only a desktop review of previously set permit limits, but actually establish the lowest emission rate for each particular HAP at an

operating facility. When reviewed as required, it becomes clear the emissions limits proposed by SWEPCO are not the maximum achievable.

Response

The comment is noted. Alternative controls were evaluated and test data were considered.

54. Reliance on the permit limits set out in applications to date; in comparison to reliance on actual test data from plants is flawed. Prior to the *New Jersey* decision, previous applicants generally employed a Best Available Control Technology ("BACT") analysis. The regulations for BACT analysis do not require that the maximum reduction in pollution be utilized; rather applicants under a BACT analysis are allowed to consider other factors. Relying on applications and permits that employed a BACT analysis does not ensure the greatest reduction in pollutants is achieved and does not represent a legitimate MACT analysis.

Response

When there were similar sources with actual data that was determined to be achieved in practice, the Department did consider and require such similar emissions limits. However, the permit issuer may rely on permit limits as reflecting the MACT floor if the permit limits reflect the emissions control achieved in practice by the relevant best performers. *Northeast Maryland Waste Disposal Auth. V. EPA*, 358 F.3d 936, 953-54 (citing *Sierra Club v. E.P.A.*,167 F.3d 658 (D.C.Cir. 1999)).

55. While SWEPCO is correct that the regulations allow for sub categorization of EGUs based on fuel type, this does not extend to processes. SWEPCO's limited its review of operating units to those plants employing its preferred alternatives. When describing the process it undertook, SWEPCO states: First, SWEPCO identified the technologies employed and the emissions limitations achieved for each specific HAP by the best controlled similar sources (i.e. the MACT floor). Then SWEPCO investigated whether any additional techniques are available and could be applied to achieve further reductions at the Turk plant, taking into consideration the cost of achieving such emission reductions, and any non-air quality health and environmental impacts and energy requirements (i.e. beyond-the-floor analysis).

Response
The MACT analysis begins by determining what category a major source is in and determining the emissions rates of other "similar sources" (defined as those structurally similar in design and capacity). The Department then must determine the MACT floor—the emission control that is achieved in practice by the best controlled similar source. Once the floor is determined, the Department must consider possible standards that are more stringent considering cost and other non-

air-quality health and environmental impacts, and energy requirements (i.e. going beyond the floor).

The Department properly limited its MACT review of similar sources to pulverized coal (PC) plants burning sub-bituminous coal.

The commenter does not state what other "processes" should have been considered. It is assumed that the commenter is referring to the PC design. Other types of coal-fired electric generating units, such as the CFB or IGCC design, were not considered because such plants are not "structurally similar in design."

56. Application p. 8. SWEPCO tries to limit the definition of "similar source" to one employing the same processes as well as fuel as proposed for Turk. The limitation of "similar source" based on processes is not justified and SWEPCO offers no substantiation for such a limited review. SWEPCO does not thoroughly evaluate the other control technology options available to reduce HAP emissions nor does it evaluate the emissions limitations applicable to units operating with differing control options. SWEPCO reviewed, though not properly, the emissions limitations for the processes that it has already selected. Any attempt to limit the MACT analysis based on the process that SWEPCO has previously determined it would like to use is improper. The standard for evaluation of SWEPCO's emission controls under 112(g) is now the maximum achievable control technology. Therefore, for example, if a wet scrubber would actually achieve a greater reduction in HAPs it must be considered, and under the regulation, seemingly employed to comply with the MACT standard. SWEPCO chooses to avoid this analysis by stating that it has chosen the "optimal" control. This is insufficient, there needs to be additional analysis to ensure that "optimal" is actually "maximum achievable" following the process set out by the regulations.

Response

This comment was previously addressed. The Department properly limited its MACT review of similar sources to pulverized coal (PC) plants burning sub-bituminous coal. The MACT analysis is an emissions-focused analysis, rather than a technology-based analysis (as is the case with the BACT). The control technology selected by SWEPCO is capable of achieving the permitted MACT emissions rates.

The Turk plant will employ a dry FGD. The comparison of wet versus dry is contained in Appendix A, which contains information from the May 7, 2008 submittal. The discussion starts on page 31 for mercury considerations and 58 for acid gasses consideration.

The information indicates that dry FGD may control HF and HCl to a higher degree. In any event there is no information to indicate dry FGD would control the gases to a lesser degree than wet FGD.

Mercury will have different removal efficiencies for wet versus dry FGD. However, mercury will be specifically controlled by an ACI system. The difference of wet verses dry does not factor into the mercury MACT emission rate.

57. To allow SWEPCO to employ permit limits above emissions rates that have been proven to be achievable defies the intent of the regulations. This type of analysis, prevalent in the SWEPCO submission and seemingly relied upon in the draft permit, violates the spirit of the MACT analysis. If one allows limits above what is actually achievable we are not requiring the maximum degree of reduction called for in 112(d)(2).

    SWEPCO's emissions would exceed current facilities operational emissions; in some instances they exceed emissions by an order of magnitude. This is not meeting MACT and should not be deemed satisfactory.

Response

ADEQ does not acknowledge that the stated levels have been "achieved" as defined in a MACT analysis. ADEQ presented the data for consideration in the analysis in determining the MACT emission rates. To be considered "achieved" the rates must be achieved over a period of time.

The application has been evaluated in accordance with the requirements of 112(g) and 40 CFR 63. One time test data is not an indication of the operational ability of other sources and is an inappropriate comparison. The operational limit of these other facilities can only be defined as their permit limits, absent sufficient test data. The Turk facility will have the same or lower permitted emission limits than these facilities that reported actual test data.

In the case of test data presented by the commenter for the Hawthorn plant, the ADEQ has agreed that these limits have been achieved over time and incorporated the results into this MACT decision as appropriate.

58. We urge ADEQ to require SWEPCO to conduct a more complete case-by-case MACT analysis, including establishing a "MACT floor" and conducting a reasoned "beyond-the-floor" analysis for the main boiler and auxiliary boiler. We urge ADEQ to require SWEPCO to provide ample documentation and explanation, including unambiguous HAP content of the fuel that will be burned in order to accurately determine (based on removal efficiencies and vendor guarantees) whether the stated controlled emission levels will be achieved. Lastly, we urge ADEQ to require monitoring sufficient to assure compliance, including the use of continuous monitoring systems.

Response

The comment is noted. The Department conducted an appropriate case-by-case MACT analysis, including establishing a MACT floor and going "beyond-the-floor." The Department has required the use of continuous monitoring systems where appropriate.

Coal is far from a uniform material. Sampling of coal for all constituents, if possible, would only yield a range of values. Upon combustion, these constituents are often portioned in the ash and air streams. An attempt to apply control efficiencies (themselves often only available in ranges), to ranges of HAP contents and ranges of emission in the air stream would not yield any useful data. As stated previously, use of control efficiencies is only one option in evaluating MACT limits and not always the most appropriate.

Effects of Pollutants

59. A commenter provided several articles linking neurological disorders to the release of ambient mercury as well as the biological accumulation of mercury. This cutting edge of scientific research demonstrates why the Turk plant air permit must be denied, in that it is a permanent, irreversible, biohazard that is unacceptable for the citizens of Arkansas.

    Numerous individuals commented construction and operation of the plant would introduce harmful levels of mercury into the environment.

    Numerous individuals commented construction and operation of the plant would introduce mercury into the environment which could lead to an increase in autism in infants.

Response

The Arkansas Department of Health (ADH) indicates a Minimal Risk Level (MRL) of 0.2 micrograms/cubic meter (ug/m3) is used for chronic-duration exposure (365 days or more) to metallic mercury (also known as elemental mercury) vapor. An MRL is defined as an estimate of daily human exposure to a substance that is likely to be without an appreciable risk of adverse noncarcinogenic effects over a specified duration of exposure. An MRL is considered to represent safe levels of exposure for all populations, including sensitive subgroups.

Furthermore, the United States Environmental Protection Agency (USEPA) has derived an inhalation reference concentration (RfCi) of 3x10-4 milligrams/cubic meter (mg/m3) for metallic mercury (0.3 ug/m3). In general, the RfC is an estimate (with uncertainty spanning perhaps an order of magnitude) of a daily inhalation exposure of the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. The RfCi for mercury is based on a lowest-observed-adverse-effect-level (LOAEL) of 0.025 parts

per million (ppm). LOAELs are concentrations below which no adverse effects have been observed. Based on this RfCi, USEPA has derived a Residential Air Screening Level of 0.31 ug/m3.

SWEPCO's total mercury emission rate is 0.0102 lbs/hr on an annual average. Using this rate and accounting for a 1 hour versus annual rate, dispersion modeling predicts ambient air impacts of 0.0028 $\mu g/m^3$ 1 hour average. This predicted concentration is far below the maximum levels established by ADH and USEPA that are protective of public health.

60. Numerous individuals commented construction and operation of the plant would contribute to or cause medical and/or health problems for close residents.

    Numerous individuals feel construction and operation of the plant will bring about air quality degradation.

    Numerous individuals commented construction and operation of the plant would cause air pollution in general.

    Numerous individuals commented that construction and operation of the plant will create a smog problem in the area of the facility.

    Numerous individuals commented that construction and operation will cause air pollution which will lead to lung cancer.

Response

These issues were addressed in the Title V/PSD draft permit decision that preceded this MACT decision. They are not addressed in this MACT decision.

However, in response to the comments, ADEQ evaluated emissions from the facility in accordance with rules, regulations and standards designed to protect the public health. This included, but was not limited to, an evaluation of air quality in relation to the National Ambient Air Quality Standards, which are specifically set at a level to ensure protection of the public health.

61. One individual commented that the federal standards are insufficient since the clean air mercury rule is no longer in effect.

Response

With the Clean Air Mercury Rule vacated, the facility is obligated to comply with the federal rules for a case by case MACT determination 112(g) requiring the

maximum degree in reduction of mercury. This permit incorporates the provisions of this requirement.

Non MACT related comments

62. SWEPCO should perform at least within limits of existing facilities, that sufficient monitoring is necessary to insure the plant is operating within its permit limits, and that the models used to assess the potential for PSD take into consideration any newly advised NAAQS. It is imperative that ADEQ insures protection and longevity of Arkansas' air quality.

Response

The comments are noted. No specific details requiring a response are presented. These issues were addressed in the Title V/PSD draft permit decision that preceded this MACT decision. They are not addressed in this MACT decision.

63. The state has dodged non-compliance of NAAQS for 03 and PM, one would think that for those emissions that are known precursors to the NAAQS, ADEQ would insure the permittee is in compliance with the permit and not contributing excessive emissions which could potentially put the state out of compliance with NAAQS. This check cannot be accurately performed with one sample per year. It is ADEQ's responsibility to insure the permittee is meeting its emission standards, with such limited sampling ADEQ is failing in its responsibilities.

Response

The pollutants related to NAAQS are not the HAP emissions that are specifically addressed in this MACT decision. NAAQS pollutants were address in the Title V/PSD draft permit decision. In that draft, a combination of continuous emission monitors, stack testing and parametric monitoring is used to assure compliance with the emission rates.

64. The permit uses models to demonstrate the conclusion that violations to the NAAQS will not occur as a result of this permit. However, you cannot find in the text any details of the model such as percent error, critical assumptions or levels of significance. Instead, there simply is a number indicating violations will or will not occur to the NAAQS.

    In the PSD models, the area of the Caney Creek and Upper Buffalo areas were evaluated. Clearly these areas are meeting NAAQS and with appropriate planning should continue to meet such standards for numerous years to come. However, the initial model did indicate there could be a problem, so multi source models were incorporated. Model integrity can easily be skewed for numerous reasons, therefore it may be advisable to show some sort of understanding for the model's levels of significance and percent error after the initial failure of the model's projections.

The significant impact level was only exceeded by PM_{10}, and appropriately, a continuation of model analyses was conducted. However, it seems that due to the fact that other parameters, such as NO_x, were clearly approaching the levels of significant impacts additional analyses of these "at risk" parameters should have been made to insure any PSD.

Response

These issues were addressed in the Title V/PSD draft permit decision that preceded this MACT decision. They are not addressed in this MACT decision.

However, in response to the question, all modeling was done in accordance with EPA guidelines found in 40 CFR 51 Appendix W and other guidelines.

Dispersion modeling uses EPA approved models which have gone through extensive review and verification. Any information regarding the sensitivity or accuracy of the models can be found in the EPA documentation.

As an approved regulatory model, the models are used as is without evaluation of the details that the commenter requests.

65. Numerous individuals commented construction and operation of the plant would contribute to or cause a noticeable increase of global warming by increasing carbon/carbon dioxide emissions.

Numerous individuals have labeled the coal plant a "dirty source of electricity" and favor cleaner alternatives.

Numerous individuals feel Arkansas should not bear the burden of pollution from a plant that will mainly serve Texas and Louisiana.

Numerous individuals commented that construction and operation of the plant will introduce harmful levels of carbon dioxide, oxides of nitrogen (and mercury).

Numerous individuals commented that construction and operation of the plant will introduce harmful levels of mercury and carbon dioxide which will lead to global warming.

Response

These issues are addressed in the comments and responses on the PSD permit.

66. Numerous individuals favor plant construction and operation.

Response

The comments are noted.

67. Numerous individuals commented that construction and operation of the plant goes against the Department's mission statement (To protect and enhance the environment).

Response

The mission statement of the Department is achieved through implementation of its rules and regulations. The Turk plant permit has been evaluated in accordance with these air permit rules and regulations.

68. Numerous individuals oppose the plant and give no reason.

Response

The comments are noted.

Comments that were incorporated by reference are out of date and based on an older application.

69. AEP's permit only requires 45% mercury control, far below levels that are commonly permitted and guaranteed today. The application fails to report the mercury concentration in the coal (or the content of any other HAP), which is required to determine control efficiency. However, the facility will fire PRB coal, which typically has no more than 0.1 ppm mercury. The mercury input to the boiler is 1.25 x 10-5 lb/MMBtu, assuming the unit bums 375 ton/hr of coal and has a heat input of 6,000 MMBtu/hr. The mercury limit of 0.04 lb/hr or 0.18 ton/yr corresponds to 6.85 x 10-6 lb/MMBtu of mercury. Thus, the mercury reduction is 45%. The proffered mercury MACT limit for the entire system, from the coal pile to the stack, will achieve less than half of the mercury reduction that is currently being achieved by two similar sources with just carbon injection.

    Response

    This comment is based on an initial 112(g) application by SWEPCO that is not the basis of this draft permit decision. Based on the supplemental applications submitted and the proposed draft permit, this comment is not relevant.

70. The case-by-case MACT process was not followed in setting the mercury MACT limit. There is no floor analysis or beyond the floor analysis, but rather, an attempt at *post hoc* rationalization of a very high mercury limit, much higher than what is currently being achieved. ADEQ should assemble all available test data, require that AEP provide coal quality data, and perform a proper mercury MACT analysis.

Response

This comment is based on an initial 112(g) application by SWEPCO that is not the basis of this draft permit decision. Based on the supplemental applications submitted and the proposed draft permit, this comment is not relevant.

71. AEP's April 9, 2008, submittal treats case-by-case MACT as a mere paper exercise and, incredibly, proposes not a single new, more stringent, emission limit for *any* of the 30 HAPs it lists in its original application.

Response

This comment is based on an initial 112(g) application by SWEPCO that is not the basis of this draft permit decision. Based on the supplemental applications submitted and the proposed draft permit, this comment is not relevant.

72. For hydrochloric (HCI) and hydrofluoric (HF) acids, AEP provides no analysis whatsoever, but simply "agrees" that the current Draft Permit limits are MACT. For HF, AEP's proposed MACT limit of 5.4 lbs/hour and 23.7 tons per year (based on a vendor specification of 9 E-4 lb/MMBtu) is *double* that of the Plum Point coal plant's 4.4 E-6 lb/MMBtu (or 90 percent control by weight).

Response

This comment is based on an initial 112(g) application by SWEPCO that is not the basis of this draft permit decision. Based on the supplemental applications submitted and the proposed draft permit, this comment is not relevant.

73. Numerous recently permitted coal-fired EGUs have received more protective mercury limits than what AEP proposes. These include, but are not limited to:
    - Mid-American Energy's Council Bluffs Unit 4 (15 E-6lb/MWh);
    - Louisville Gas & Electric Trimble Unit 2 (13 E-6lb/MWh);
    - Bull Mountain Energy Roundup Units 1and 2 (26.4 E-6lb/MWh);
    - WE Energy Elm Road Units 1 and 2 (11 E-6 lb/MWh);
    - Public Service Company Comanche Station 3 (20 E-6 lb/MWh);
    - Omaha Public Power District Nebraska City Unit 2 (18 E -6lb/MWh); and
    - Wisconsin Public Service Corporation Weston Unit 4 (15 E -6 lb/MWh).

Response

This comment is based on an initial 112(g) application by SWEPCO that is not the basis of this draft permit decision. Based on the supplemental applications submitted and the proposed draft permit, this comment is not relevant. Some of these units are further mentioned in later mercury comments and ADEQ responses.

74. AEP claims that mercury limits of 0.04 lbs/hr and 0.18 tons/year are MACT. These limits, which are no more stringent than what was proposed in the original application and draft permit appear to be derived from the NSPS Subpart Da (fuel specification), or 66 E-6 lb/MWh. These limits do not satisfy mercury MACT for many reasons.

Response

This comment is based on an initial 112(g) application by SWEPCO that is not the basis of this draft permit decision. Based on the supplemental applications submitted and the proposed draft permit, this comment is not relevant.

75. AEP's analysis does not address the MACT floor, namely, it fails to identify the best performing similar source and its emissions. In fact, the proffered BACT limit for mercury from the PC boiler is much higher than the best controlled similar source identified by the EPA in its 1998 ICR database. The best controlled similar source identified by EPA in 2004, based on its 1998 ICR database, emitted 2.0 lb/TBtu or 2.0 x 10^{-6} MMBtu of mercury when firing sub-bituminous coal (though we do not concede that it is proper to categorize sources based on fuel type). AEP's proffered "MACT = BACT" limit corresponds to 6.85 x 10-6 lb/MMBtu, or four times higher than the floor based on data collected in 1997. Considerably more data is available today. ADEQ should gather this information and use it to make a proper floor finding.

Response

This comment is based on an initial 112(g) application by SWEPCO that is not the basis of this draft permit decision. Based on the supplemental applications submitted and the proposed draft permit, this comment is not relevant.

76. AEP states that it "has not identified any existing coal-fired generating units burning sub-bituminous coals that have employed a mercury-specific control technology on a long-term basis." MACT App., p. 8.

ADEQ should obtain all available mercury monitoring data from these two facilities and use it together with other data to establish a proper mercury floor. Thus, AEP's assertion that "the MACT determination for mercury for the main boiler is based on emerging technologies, and exceeds the level of control achieved in practice by the best controlled similar sources operating today" is false.

Response

This comment is based on an initial 112(g) application by SWEPCO that is not the basis of this draft permit decision. Based on the supplemental applications submitted and the proposed draft permit, this comment is not relevant.

77. SWEPCO needs to discuss condensable controls. Also, SWEPCO will need to address the lower limits at Sithe and Comanche (both have lower filterable and

condensable limits at 0.01/0.02 lb/MMBtu). Kansas City Iatan has a limit of 0.0236 lb/MMBtu and many other permits have a limit of 0.018.

Response

This comment is based on an initial 112(g) application by SWEPCO that is not the basis of this draft permit decision. Based on the supplemental applications submitted and the proposed draft permit, this comment is not relevant. Refer to the comment and response on PM_{10} emission rates elsewhere in this document for further details.

ADEQ OPERATING AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation 26:

Permit No. : 2123-AOP-R0
IS ISSUED TO:

John W. Turk, Jr. Power Plant
Hwy. 335, 2 Miles North of Fulton
Fulton, AR 71838
Hempstead County
AFIN: 29-00506

THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

November 5, 2008 AND November 4, 2013

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Mike Bates

Mike Bates
Chief, Air Division

November 5, 2008
Date

Table of Contents

List of Acronyms and Abbreviations

A.C.A.	Arkansas Code Annotated
ACI	Activated Carbon Injection
acf	Actual Cubic Feet
AFIN	ADEQ Facility Identification Number
CAMR	Clean Air Mercury Rule
CEM	Continuous Emission Monitor
CFR	Code of Federal Regulations
CO	Carbon Monoxide
HAP	Hazardous Air Pollutant
Hg	Mercury
lb/hr	Pound Per Hour
lb/MMBtu	Pound per million British Thermal Unit
lb/TBtu	Pound per Trillion British Thermal Units
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO_x	Nitrogen Oxide
NSPS	New Source Performance Standard
Pb	Lead
PC	Pulverized Coal
PM	Particulate Matter
PM_{10}	Particulate Matter Smaller Than Ten Microns
ppm	Parts Per Million
PRB	Powder River Basin
SN	Source Number
SNAP	Significant New Alternatives Program (SNAP)
SO_2	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

SECTION I: FACILITY INFORMATION

PERMITTEE:	John W. Turk, Jr. Power Plant
AFIN:	29-00506
PERMIT NUMBER:	2123-AOP-R0
FACILITY ADDRESS:	Hwy. 335, 2 Miles North of Fulton Fulton, AR 71838
MAILING ADDRESS:	P.O. Box 660164 Dallas, Texas 75266-0164
COUNTY:	Hempstead
CONTACT POSITION:	Kris Gaus
TELEPHONE NUMBER:	(214) 777-1113
REVIEWING ENGINEER:	Thomas Rheaume, PE
UTM North South (Y):	Zone 15: 424.735
UTM East West (X):	Zone 15: 3,723.20

SECTION II: INTRODUCTION

Summary of Permit Activity

Southwest Electric Power Company (SWEPCO), a unit of American Electric Power (AEP), proposes to construct a new coal-fired electric power generating facility near Fulton, Arkansas, in Hempstead County. This facility will be named the John W. Turk, Jr. Power Plant. The main steam generating unit will consist of one ultra-supercritical pulverized coal boiler powering a single steam turbine designed for base load operation with a nominal net power output of 600 megawatts. This boiler will burn sub-bituminous coal and natural gas. The major permitted emission rates for this facility are 801.56 tpy PM, 732.26 tpy PM_{10}, 2102.69 tpy SO_2, 23.08 tpy VOC, 3952.0 tpy CO, 1336.6 tpy NO_x, and 110.38 tpy H_2SO_4.

Process Description

Coal Handling

Coal is unloaded by an enclosed rotary car dumper through two underground hoppers onto belt feeders BF-1/2. The coal unloading drops are designated TP-1. Surfactant sprays are used at the rotary car dumper to minimize dusting. The underground belt feeders BF-1/2 drop the coal onto coal conveyor C-1. This drop point is designated TP-2. Residual sprays are used at TP-2 to further minimize dusting. Emissions from TP-1 and TP-2 are exhausted through the coal dumper tunnel exhaust fan (SN-EP-1).

Coal conveyor C-1 carries the coal from underground and drops it in the enclosed transfer house onto either conveyor C-2 or C-5A. Conveyor C-2 carries the coal to the enclosed head house above lowering well 1 at active coal pile A or to coal conveyor C-3, which then carries it to lowering well 2 at active coal pile B. Residual sprays are used at the drop from conveyor C-1. Emissions are generated from the open drops from conveyor C-1 to lowering well 1 (SN-EP-3), from conveyor C-1 to conveyor C-3 (SN-EP-2), and from conveyor C-3 to lowering well 2 (SN-EP-4).

Emissions are generated from wind erosion at active coal pile A (SN-F-1), active coal pile B (SN-F-2), and the inactive coal pile (SN-F-4), and dozing activities among the piles (SN-F-3).

Coal is reclaimed from the active coal piles in the underground reclaim tunnel. The underground reclaim drops include two rotary plow drops onto conveyor C-4 designated TP-3 and TP-5, a drop on the conveyor C-4 line designated TP-7. Surfactant sprays are used at the rotary plow drops and fog is used at the conveyor line drops. Emissions from the underground coal reclaim tunnel drops TP-3, TP-4, TP-5, TP-6, TP-7, and TP-8 are exhausted through two coal reclaim tunnel exhaust fans (SN-EP-5/6).

Conveyor C-4 carries the coal from the underground reclaim tunnel to the enclosed transfer house where it drops onto conveyor C-5A. Conveyor C-5A carries the coal to the crusher house surge bins. The enclosed (in the crusher house) drops to the surge bins are designated TP-9 and

TP-10. The surge bins are each equipped with a bin vent filter (SN-TP-11 and SN-TP-12). From the bottom of the surge bins, coal is unloaded by belt feeders BF-3/4, which drop to coal into crushers. These drops are designated TP-13 and TP-14. After being crushed, the coal is dropped onto conveyor C-6A. These drops are designated TP-15 and TP-16. Fog is used at the crusher drops. Emissions generated from drops TP-9, TP-10, TP-13, TP-14, TP-15, and TP-16 within the coal crusher house are exhausted through two coal crusher house exhaust fans (SN-EP-7/8).

A reclaim conveyor pulls some coal from conveyor C-6A to the sample house. Emissions generated at the sample house are exhausted through the sample house exhaust fan (SN-EP-9).

Conveyor C-6A carries the coal from the crusher house to the power plant and drops it on tripper conveyor C-7A. These drops are designated TP-18 and TP-19. Fog is used at the conveyor-to-tripper conveyor drops. The tripper conveyors drop the coal into the in-plant storage silos. These drops are designated TP-20 and TP-21. Emissions generated from drops TP-18, TP-19, TP-20, and TP-21 within the power plant are exhausted through a wet fan dust collector (SN-EP-10).

Power Plant

An ultra-supercritical pulverized coal (PC) boiler (SN-01) produces steam to drive a condensing steam turbine to generate electricity. The PC boiler burns sub-bituminous coal as the main fuel and uses natural gas for startup and flame stabilization. A natural gas-fired auxiliary boiler (SN-02) is also used during startup of the PC boiler.

During normal operation, emissions from the PC boiler are controlled using low-NO_X burners (LNB) with over-fire air (OFA), selective catalytic reduction (SCR), dry flue gas desulfurization (DFGD)/spray dryer absorber (SDA), and pulse jet fabric filtration (i.e., PJFF baghouse) and activated carbon injection (ACI).

Cooling water used in the steam turbine condenser is provided by a mechanical draft cooling tower (SN-CT-1). Plant makeup water is treated in the onsite water treatment facility.

Anhydrous ammonia for use in the SCR system is stored in tanks equipped with pressure vent valves set to minimize standing losses. The ammonia is vaporized and transported from the storage tanks to the injection location.

Lime Handling

Lime for use in the SDA is delivered by rail, unloaded with a vacuum pneumatic system, and pneumatically conveyed to a lime storage silo. The exhaust point for this system is the two Lime Vacuum Conveyor (Railcar Unloading) Exhausters (SN-EP-15 and SN-EP-16). The lime silo is equipped with a bin vent filter (SN-EP-17). From the storage silo, the lime is pneumatically conveyed to the lime day bin(s) in the lime-slurry preparation area. The lime day bin(s) are equipped with bin vent filters (SN-EP-18 and SN-EP-19). Lime from the day bin(s) is formed into a slurry in a lime slaking system. The slurry is then pumped to the SDA.

Fly Ash and FGD Waste Handling

Fly ash and FGD waste removed from the flue gas is pneumatically conveyed to storage silos. The storage silos are equipped with bin vent filters (SN-EP-21 and SN-EP-22). Each vacuum conveyance system has exhausters (SN-EP-23 and SN-EP-24). From the storage silos, the fly ash/FGD waste is mixed with water and then drop loaded into open top dump trucks (SN-TP-22). The dump trucks unload the fly ash/FGD waste to an onsite landfill (SN-TP-23). Emission may be generated by wind erosion of the landfill (SN-F-6), dozing of the fly ash/FGD waste and overburden (SN-F-5), and by the haul roads (SN-RD-1).

Bottom ash, which includes furnace ash from the boiler, pyrites from the mills, and economizer ash, is collected in a submerged, water-filled trough and then conveyed to a storage bunker. From the bunker, the bottom ash is loaded into trucks and hauled to disposal. Any emissions from the handling of bottom ash are accounted for above.

Emergency Equipment

A diesel-fired emergency generator (SN-03) is used to supply power during outages and a small diesel-fired engine (SN-04) is used to pump water needed for fire suppression. Diesel fuel is stored in tanks (insignificant activity).

Prevention of Significant Deterioration

This facility is considered to be a new major source under 40 CFR 52.21, Prevention of Significant Deterioration (PSD) regulations. This SWEPCO facility will have significant emissions of PM/PM_{10}, SO_2, VOC, CO, NO_x, lead (Pb) and sulfuric acid mist (H_2SO_4) and is required to undergo PSD review for these pollutants.

Class II Ambient Air Impact Analysis

Since the total facility-wide emissions exceed the PSD significant emission rates for NOx, CO, PM_{10}, Lead and SO_2, an air quality analysis is required to demonstrate that these emissions do not cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) or exceed a PSD increment.

For PSD permits, a full ambient air impact analysis is required for each pollutant from which the net emission increase will result in an ambient impact over the predetermined level. This level is known as the "significant impact level" (SIL) and the analysis of emissions with respect to these levels is known as the "significance analysis". The following table shows the results of the significance analysis. The significance analysis shows a full impact analysis was required for

PM_{10}. A full impact analysis was conducted for lead since there is no Lead SIL, a full impact analysis is always needed.

Pollutant	Averaging Period	Maximum Modeled Concentration ($\mu g/m^3$)	Significant impact Level ($\mu g/m^3$)
CO	1-hour	23.7	2,000
	8-hour	12.9	500
PM_{10}	24-hour	19.68	5
	Annual	2.97	1.0
NO_x	Annual	0.91	1.0
SO_2	3-hour	10.38	25
	24-hour	4.22	5
	Annual	0.49	1.0

Lead NAAQS Analysis

Pollutant	Averaging Period	Highest Modeled Concentration with Background ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	% of NAAQS
Pb	Calendar Quarter	0.35044	1.50	23.4

PM_{10} full impact analysis

Pollutant	Averaging Period	Highest Modeled Concentration with Background ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	% of NAAQS
PM_{10}	24-hour	62.8	150	41.87
	Annual	25.05	50	50.02

Arkansas Regulations require further analysis if a facility consumes more than 50% of any available long term increment and 80% of any short term increment. The following table shows the results of the PSD Class II increment modeling for PM_{10}. As demonstrated, no further analysis is needed.

Averaging Period	Year of Maximum Impact	Modeled Concentration ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)	% Consumed
24-Hour	2004	13.92	30	46.4%
Annual	2001	3.22	17	18.9%*

* Since the modeling results showed the facility and surrounding sources consumed no more than 50% of the long term increment was consumed, it is mathematically impossible for the facility to have consumed more than 50% of the available long term increment.

Class I Analysis

The Clean Air Act Amendments of 1977 included provisions for the protection of visibility in designated Class I areas. These requirements are detailed in USEPA's PSD program in 40 CFR Parts 51 and 52. Federal Land Managers (FLM) have the responsibility of evaluating the effects of air pollution in such designated areas. This includes evaluating potential impacts due to visibility degradation, ambient pollutant concentrations, and increment consumption. The FLM typically follow the recommendations of the "Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts" (EPA 454/R-98-019) and the "Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase 1 Report" (December 2000) for air quality dispersion modeling analyses.

If a proposed project is predicted to have maximum modeled air quality concentrations in the Class I areas less than the significant impact levels (SILs), then it is assumed that the project will not have a significant impact and no further air quality analyses are necessary. The CALMET/CALPUFF models were run to evaluate the impact of the proposed sources on both the Caney Creek and Upper Buffalo Class I areas. The results are presented below.

Class I Area	Year	Maximum Modeled Concentrations ($\mu g/m^3$)					
		SO_2			PM_{10}		NO_x
		3-hour	24-hour	Annual	24-hour	Annual	Annual
Caney Creek	2001	2.35	0.558	0.0298	0.353	0.0196	0.0238
	2002	2.29	0.439	0.0226	0.301	0.0143	0.0182
	2003	2.34	0.570	0.0279	0.305	0.0180	0.0239
Upper Buffalo	2001	0.389	0.159	0.00645	0.105	0.00632	0.00343
	2002	0.669	0.165	0.00801	0.137	0.00697	0.00539
	2003	0.518	0.169	0.00633	0.119	0.00586	0.00389
Class I Area SIL ($\mu g/m^3$)		1.0	0.2	0.1	0.3	0.2	0.1
Class I Area Increment ($\mu g/m^3$)		25	5	2	8	4	2.5

Multi-Source Increment Modeling Analysis

Because the SO_2 and PM_{10} concentrations exceeded the SILs listed above, multi-source modeling was required for SO_2 and PM_{10} short-term averaging periods.

In the case of total SO_2 impacts, sometimes the predicted total impacts exceeded the allowable increment. The following tables summarize the results.

Class I Area	Year	Highest-First-High Modeled SO_2 Concentrations (µg/m^3)					
		3-Hour Average			24-Hour Average		
		Inventory	Project	Total	Inventory	Project	Total
Caney Creek	2001	34.48	0.00	34.48	9.40	0.03	9.44
	2002	44.00	0.00	44.00	5.87	0.00	5.87
	2003	39.53	0.00	39.53	8.24	0.00	8.24
Upper Buffalo	2001	n/a	< SIL	n/a	n/a	< SIL	n/a
	2002	n/a	< SIL	n/a	n/a	< SIL	n/a
	2003	n/a	< SIL	n/a	n/a	< SIL	n/a
Class I Area SIL (µg/m^3)		1.0	1.0	1.0	0.2	0.2	0.2
Class I Area Increment (µg/m^3)		25	25	25	5	5	5

To comply with the PSD increments, the proposed sources must not make a significant contribution to any second, third, fourth, etc. highest values at all receptors with a predicted exceedance of the PSD Increment in the Class I areas.

Since the proposed Turk facility's impacts are below the significant impact level during any of the predicted exceedences, the facility does not contribute significantly to any of these predicted total concentrations that may be above allowable Class I increments (due to other increment consuming sources). These impacts are summarized below.

Averaging Time	Increment (µg/m^3)	Highest Turk Impact when Total Impacts > Increment (µg/m^3)	Significant Impact Level (µg/m^3)
3 Hour	25	0.0	1.0
24 Hour	5	0.19*	0.2

* Based on the 2nd high at each receptor

Similar analyses were performed to determine the potential PM_{10} impacts at Caney Creek from all PSD increment consuming sources identified. The results of this analysis are summarized in the following table. These results indicate that all predicted highest-2nd-high concentrations are well below the allowable PSD increment concentrations.

Class I Area	Year	Modeled Concentrations PM_{10} ($\mu g/m^3$)			
		24-Hour Highest-First-High		24-Hour Highest-Second-High	
		Total Concentration	Project Contribution	Total Concentration	Project Contribution
Caney Creek	2001	0.42	0.33	0.36	0.28
	2002	0.41	0.03	0.40	0.00
	2003	0.51	0.00	0.44	0.16
Class I Area SIL ($\mu g/m^3$)		0.3	0.3	0.3	0.3
Class I Area Increment ($\mu g/m^3$)		8	8	8	8

Class I Visibility

Modeling was performed to determine the how the emissions from the proposed sources will impact the visibility in the Caney Creek and Upper Buffalo Class I area. Using alternative CALPOST methods and AERMOD dispersion, SWEPCO was able to show that no events in any of the three years modeled at Caney Creek have a predicted maximum change in light extinction greater than 10%. Further, the Method 6 AERMOD dispersion results for Caney Creek based on the annual average extinction background visual range and highest-eighth-high value are below 5% for all three years modeled. The results at the Upper Buffalo Class I area also indicate that the predicted change in light extinction with the turbulence based dispersion and the alternative Method 6 are minimal. Considering the results based on the application of both the latest alternative methods for calculation of light extinction and the less conservative turbulence-based dispersion option, it is concluded that the John W. Turk, Jr., project will not have a significant impact on visibility at the Caney Creek or Upper Buffalo Class I areas.

The USDA/Forest Service reviewed the visibility modeling and predicted impacts. Based on the results of Method 2 analysis alone, the Federal Land Manager (FLM) required mitigation of the predicted visibility impacts. SWEPCO proposed and the FLM accepted voluntary reductions of SO_2 emissions at the SWEPCO Welsh plant in Texas to offset any visibility impacts. The offsets/emission reductions were based on modeling the visibility impacts of the Welsh plant on the Caney Creek Class I area. A SO_2 emission rate was established that mitigated an equivalent number of days that the Method 2 analysis for the Turk plant predicted impacts over 5%. These emission rates and conditions are contained in the Plantwide Conditions of this permit.

BACT Analysis Summary

For this BACT analysis, potential control technologies (and resulting emission limits) were identified using the most recent version (dated October 20, 2005) of the Coal-fired Utility Database and a query of the RBLC database (for coal-fired external combustion units for which

PSD permits have been issued since 1990) as well as SWEPCO's experience in building and operating coal plants. For all pollutants except CO and VOC, the RBLC database did not identify any relevant units beyond those already contained in the Coal-fired Utility Database. For approximately 50 of the relevant units identified in these databases, the information provided was compared against (and revised, where necessary) available permitting information to further investigate and evaluate possible control technologies and the performance levels of those technologies.

BACT Evaluation for Main Boiler

The following technologies were considered for the main boiler (SN-01).

Pollutant	Coal-Fired Boiler Control Technologies
$PM/PM_{10}/Pb$	Baghouse Electrostatic Precipitator (ESP) Venturi Scrubber
SO_2	Wet Flue Gas Desulfurization (WFGD) Dry Flue Gas Desulfurization (DFGD)
VOC	Catalytic Oxidation Proper Boiler Design and Operation
CO	Catalytic Oxidation Proper Boiler Design and Operation
NO_x	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Low NO_x Burners (LNB) / Over-Fire Air (OFA) Flue Gas Recirculation (FGR)
H_2SO_4 Mist	DFGD with a Baghouse WFGD with a Wet ESP Sorbent Injection

The second step in the BACT analysis is to eliminate any technically infeasible control technologies. Each control technology for each pollutant is considered, and those that are clearly technically infeasible are eliminated.

The only technically infeasible options are flue gas recirculation for NO_x control and catalytic oxidation for CO and VOC control.

Flue Gas Recirculation

FGR is primarily used to reduce thermal NO_x formation. Emissions due to fuel-bound NO_x, which are significant for coal-fired boilers, are not meaningfully affected by FGR. Moreover, the reduction in thermal NO_x is accomplished by recirculating the flue gas into the windbox. However, for coal-fired boilers operating at peak boiler capacity the recirculated flue gas is needed to control temperature in the secondary superheater and reheater and is commonly readmitted above the windbox. This method of FGR does not reduce NO_x emissions. Therefore, FGR is not technically feasible to control NO_x emissions from PC boilers.

Catalytic Oxidation

Catalytic oxidation is not technically feasible for use with coal-fired boilers because the catalyst consists of several precious metals that are easily contaminated by sulfur compounds in the flue gas and are eroded and destroyed by the high levels of fly ash in the flue gas. No currently available catalyst material can operate in the harsh conditions resulting from coal combustion. In addition to the technical considerations, the oxidation catalyst would create adverse environmental impacts (by oxidizing more SO_3 and therefore creating more H_2SO_4 mist emissions) and adverse energy impacts (due to the increase in pressure drop across the system). Furthermore, SWEPCO is not aware of any installations worldwide of catalyst on a coal-fired unit. As catalytic oxidation is not technically feasible, this option is removed from BACT consideration.

The control technologies are then ranked in order of effectiveness and then the control technologies are evaluated on the basis of economic, energy, and environmental considerations.

PM/PM_{10}/Pb Controls

A baghouse has the highest control efficiency of any of the particulate control options, and therefore, according to the "top-down" approach, is considered first. A baghouse is chosen as BACT for PM and Pb control. In accordance with EPA guidance, the remaining particulate control devices (i.e., ESP and venturi scrubber) are not considered further since the highest efficiency (99.9%) control device is selected as BACT.

SO_2 *Controls*

Two common SO_2 control techniques exist for coal-fired boilers: WFGD and DFGD. In a FGD system, an alkaline reagent (usually lime or limestone) is injected into the flue gas, where it reacts with and collects the SO_2. WFGD has the highest control efficiency of the two SO_2 control options, and therefore, according to the "top-down" approach, is considered first. In a WFGD system, the alkaline reagent is in the form of a slurry. The flue gas is routed to a spray tower where it is contacted by the slurry. A mist eliminator removes moisture from the flue gas as it exits the WFGD system. The control cost for a WFGD is approximately \$1,832.00/ton SO_2 removed. There are several challenging environmental impacts associated with WFGD systems. The large volume of used wet caustic mixture produced by WFGD must be treated and disposed. The WFGD waste product can be recycled, but is most often sent to a landfill. Also, the moisture added to the flue gas by a WFGD system creates a visible vapor plume, prevents the use of opacity monitors downstream of the WFGD, and results in increased nearby ground level impacts due to the cooler, less buoyant plume.

Make-up water consumption to the FGD system would increase by approximately 900% when going from the proposed dry system to a wet system. This is because the Dry FGD system at the Turk Plant will utilize process wastewater from the cooling tower and other plant processes for approximately 80% of the total water requirement, as compared to 100% treated make-up water required for a Wet FGD. Much of the wastewater produced in the Wet FGD cannot be reused continuously in the process and must be purged from the system and sent to a wastewater treatment system to remove suspended solids, dissolved mercury, and for pH adjustment before it is sent to an outfall. The wastewater treatment system is estimated to cost \$30 – \$35 Million based on similar systems being installed on the AEP fleet, and will produce up to approximately 4.25 tons per hour (TPH) of additional solid waste material that will need to be disposed in the landfill. Dry FGD systems produce essentially no additional wastewater discharge to local streams/rivers.

SO_3 and sulfuric acid mist emissions are also expected to be 6.5 to 40% lower with the use of the Dry FGD system due to the use of lime as the process reagent. Lime inherently absorbs acid mist and the Turk Plant sulfuric acid emissions are expected to be approximately 30 lb/hr without additional means of SO_3 / H_2SO_4 mitigation. The wet FGD system would likely require a Trona or other sorbent injection system, estimated to cost approximately \$10 Million, to reduce SO_3 / H_2SO_4 emissions to levels matching that of the dry FGD system. A Trona injection system is expected to add 0.5 – 1.0 TPH of additional solid waste to the fly ash that will need to be disposed in the landfill.

Additional solid waste streams from the wastewater treatment system and the Trona Injection system could add up to 45,000 TPY of additional solid waste to the landfill. This additional waste (depending on its density) could require up to 17 acres of additional landfill at a cost of \$4.25 Million.

Auxiliary power demand for the proposed Dry FGD system at the Turk Plant is approximately 0.6% of net unit output, or 3.7 MW. Typical auxiliary power demand for a Wet FGD system on a similar sized unit burning sub-bituminous coal is 1.0 to 1.5% of net unit output. Therefore, a Wet FGD system at the Turk Plant would likely consume 6 to 9 MW of auxiliary power. To maintain the nominal net unit output, the Turk Plant would have to be permitted to burn approximately 1.5 to 3.4 tons/hr of additional PRB coal to make up for the additional auxiliary power demand imposed by the Wet FGD. This near 0.5 to 1.0% increase in total fuel consumption would have a directly proportional impact on unit emissions. While the SO_2 emissions would be offset by the increase in efficiency of the Wet FGD system, increases in NO_x, PM, CO_2, etc. of 0.5 to 1.0% would not be offset.

The additional auxiliary power demand from the wet FGD system results in lost unit capacity that could range from 18,000 – 40,000 MWH per year. Unless Turk is permitted to burn additional fuel, the lost capacity will likely be recovered by means of purchasing the power on the open market. Assuming \$30/MWH, the resulting energy replacement cost would range from \$540,000 - \$1,200,000 annually.

Total PM has the potential to be higher in wet FGD systems due to gypsum fines and acid mist in the flue gas. Wet FGD systems can also contribute greater fugitive PM emissions due to the need for large limestone storage piles and handling systems.

While no quantitative data exists to support a claim, the proposed Dry FGD system at the Turk Plant appears better suited for mercury (Hg) capture. The Turk Plant's Dry FGD system will be equipped with a Powdered Activated Carbon (PAC) injection system immediately upstream of the SDA vessel, which provides excellent flue gas mixing and residence time for the carbon to absorb the oxidized Hg in the flue gas. The baghouse ultimately captures the Hg before it is released to the atmosphere. While an activated carbon injection (ACI) system would likely be used in conjunction with a wet FGD system, the absence of an SDA vessel to provide mixing could result in less efficient mercury capture.

The most significant difference between Dry Flue Gas Desulfurization (FGD) technology and Wet FGD technology concerns the up-front capital cost, which is approximately $102 Million versus $233 Million respectively for a 600 MW 100% PRB application like the Turk Plant. Looking at these capital cost estimates on an annual $/ton SO_2 removed basis (assuming a 15% capital carrying charge), the dry FGD system is roughly 45% of the cost of the wet FGD system ($647/ton removed for Dry FGD versus $1422/ton removed for Wet FGD). However, the capital cost differential between the two technologies (approx $131 Million) for the additional 920 tons of SO_2 removed annually by the wet system over the dry system, yields a cost of approximately $21,000/ton removed for the additional SO_2 capture. A major driver in the capital cost increase to go to a wet scrubber lies in the materials of construction (e.g. major equipment, piping, ductwork, stack liner, etc. must be constructed of alloy or fiberglass materials), and while this adds to up front capital cost, it also means higher operations and maintenance costs throughout the life of the plant.

Based on the energy and environmental factors discussed above, WFGD is eliminated from consideration as BACT.

CO and VOC Control

For a coal-fired boiler, emissions of CO and VOC are the result of incomplete combustion and thus represent uncaptured energy. Therefore, units have an incentive from a production standpoint to reduce CO and VOC emissions through proper boiler design and operation. Operating with higher flame temperatures and longer furnace residence times can reduce CO and VOC emissions. Unfortunately, reducing CO and VOC emissions can result in an increase of NO_x emissions from the boiler. No post combustion CO and VOC controls have been demonstrated for coal-fired facilities.

Proper design and operation of the boiler is the only effective control option. Emissions of CO and VOC have traditionally been maintained very low by design. Therefore, proper boiler design and operation is selected as BACT for CO and VOC.

NO_x Control

SCR has the highest control efficiency of any of the NO_x control options, and therefore, according to the "top-down" approach, is considered first. Based on the review of EPA's control technology databases, all modern PC boilers use a combination of SCR and LNB to control NO_x. SWEPCO's proposed boiler will be equipped with SCR and LNB (with OFA) as BACT for NO_x control. In accordance with EPA guidance, the remaining NO_x control devices are not considered further in the BACT analysis since the highest efficiency control device is selected as BACT.

H_2SO_4 Mist Control

Until recently, H_2SO_4 mist received minimal review in permits. However, it has received increased attention for boilers equipped with SCR since the SCR oxidizes some portion of the SO_2 to generate additional SO_3, which reacts with water in the exhaust stream to produce H_2SO_4.

The two primary techniques for H_2SO_4 mist control are WFGD with a Wet ESP and DFGD with a baghouse. Both control techniques involve scrubbing with an alkali followed by particulate control. DFGD and a baghouse have been selected as BACT for the proposed boiler for SO_2 and PM/PM_{10} control, respectively. Therefore, a WFGD and Wet ESP system is not feasible for H_2SO_4 mist control for the proposed boiler. Moreover, DFGD followed by a baghouse provides for the most H_2SO_4 mist removal of the control options. Therefore, a DFGD system with a baghouse is chosen as BACT for H_2SO_4 mist control.

Additional sorbent injection is not practical for use on the proposed boiler since it will be equipped with a DFGD system (as a result of the SO_2 BACT analysis). H_2SO_4 mist in the flue gas will be captured by the alkaline scrubbing agent in the DFGD system. Additional sorbent injection would only serve to add more alkali to the flue gas stream. SWEPCO will be able to meet BACT level limits for H_2SO_4 mist emissions by, among other things, controlling the amount of scrubbing agent used in the DFGD system. Therefore, additional sorbent injection is eliminated from further consideration in this BACT analysis.

SWEPCO proposed a limit of 0.10 lbs/MMBtu and later revised it to 0.08 lbs/MMBtu during the draft period. ADEQ added an additional limit of 0.065 lbs/MMBtu while combusting coal containing less than 0.45% sulfur after the draft, in response to comments, and based on the latest information for similar permits.

BACT Selection

The following table summarizes the BACT and associated emissions limits chosen for the Main Boiler (SN-01) this facility. These BACT limits are consistent with those found at similar facilities.

Main Boiler (SN-01)				
Pollutant	*Control Technology Determination*	*BACT Limit*	*Averaging period*	*Compliance Method*

PM (filterable)	Baghouse	0.012 lb/MMBtu	3-hour	Method 5 or 17
PM_{10} (filterable)	Baghouse	0.012 lb/MMBtu	3-hour	Method 5 or 17
PM_{10} (total)	Baghouse	0.025 lb/MMBtu	3-hour	Methods 5 or 17 and 202
SO_2	Dry Flue Gas Desulfurization	0.08 lb/MMBtu While combusting coal with a sulfur content greater than 0.45% by weight	30-day rolling average	CEM
		0.065 lb/MMBtu While combusting coal with a sulfur content less than or equal to 0.45% by weight	30-day rolling average	CEM
		480 lbs/hr	24 hour rolling average	CEM
VOC	Proper Design/Operation	0.0036 lb/MMBtu[1]	3-hour	Method 25
CO	Proper Design/Operation	0.15 lb/MMBtu	30-day rolling	CEM
NO_x	SCR	0.067 lb/MMBtu for normal operations[2]	24-hour rolling average	CEM
		420 lbs/hr	24 hour rolling average	CEM
		0.05 lb/MMBtu	Annual average	CEM
Pb	Baghouse	2.6E-5 lb/MMBtu[3]	3-hour	Method 12 or 29
H_2SO_4 Mist	DFGD with Baghouse	0.0042 lb/MMBtu	3-hour	Method 8

[1] VOC rate based on 112(g) analysis will be set at 0.00078 lb/MMBtu
[2] Normal operation is defined as operation at or above 300 MW gross output from the Unit 1 generator
[3] Pb rate based on 112(g) analysis will be set at 1.6 E-05 lb/MMBtu

BACT Evaluation for Auxiliary Boiler

A BACT analysis was also performed for emissions from the auxiliary boiler (SN-02). An auxiliary boiler with a nominal heat input capacity of 555 MMBtu/hr will be constructed and operated on an as needed basis for start-up purposes. The auxiliary boiler will be fired with natural gas only and will be limited to an annual heat input of 277,500 MMBtu (equivalent to operating 500 hours per year at full capacity).

EPA's RBLC is used as the primary data source for existing limits for comparable boilers. The generally comparable source type is natural-gas fired boilers with heat input capacities greater than 400 MMBtu/hr. However, most of the boilers of this size listed in the RBLC are intended to operate continuously. Therefore, the most comparable source type is other similar-sized auxiliary boilers. The RBLC includes five (5) facilities with similar-sized part-time auxiliary boilers.

NO_x Control

While there is a range of potential control technologies available to control NOx, the only two technologies (besides good combustion practices / fuel specification) found for generally comparable sources in the RBLC are LNB and FGR. SWEPCO proposes a BACT limit of 0.11 lb/MMBtu for NO_x emissions from the auxiliary boiler. This limit is equivalent to the recently published NSPS Subpart Db limit and is comparable to the lowest limit presented in the RBLC. SWEPCO proposes to implement the limit on a 30-day rolling average basis (same as NSPS Subpart Db).

SO_2 *Control*

Based on the RBLC review, the sole control technology determined as BACT for generally comparable units is control of the inlet fuel sulfur. SWEPCO proposes an emission limit of 0.6 lb/MMscf (approximately equivalent to 0.0006 lb/MMBtu), based on AP-42 and typical pipeline natural gas sulfur content, as BACT for the auxiliary boiler. Per NSPS Subpart Da, which sets a limit of 0.15 lb/MMBtu, compliance with the emission limit will be achieved through the use of natural gas as the only fuel.

PM Control

Similar to SO_2, the sole control technology determined as BACT for PM in the RBLC for comparable units is combustion of clean burning fuels. SWEPCO proposes an emission limit of 7.6 lb/MMscf (approximately equivalent to 0.0076 lb/MMBtu), based on AP-42, as BACT for the auxiliary boiler. The applicable NSPS Subpart Da limit is 0.015 lb/MMBtu. Compliance with the emission limit will be achieved through the use of natural gas as the only fuel.

Pb Control

Per AP-42, lead is a trace compound in natural gas. As such, BACT for Pb is proposed as a work practice standard based on using only natural gas as fuel in the auxiliary boiler. No emission limit or testing is proposed for Pb from this source.

VOC/CO Control

While there is a range of potential control technologies available to control CO and VOC, there is only one technology found for generally comparable sources in the RBLC: good combustion practices. The Boiler MACT establishes a CO work practice standard of 400 ppmvd at 3 percent oxygen (30-day rolling average basis) and requires a CO CEMS. SWEPCO proposes the Boiler MACT work practice standard as BACT for CO. VOC BACT is proposed as 5.5 lb/MMscf (approximately equivalent to 0.0055 lb/MMBtu), based on AP-42.

The following table summarizes the BACT and associated emissions limits chosen for the Auxiliary Boiler (SN-02) this facility.

Auxiliary Boiler (SN-02)			
Pollutant	*BACT Determination*	*BACT Limit*	*Averaging Time*
PM/PM_{10}	Natural Gas Combustion	0.0076 lb/MMBtu[1]	3-hour
SO_2	Natural Gas Combustion	0.0006 lb/MMBtu	3-hour
VOC	Proper Design/Operation	0.0055 lb/MMBtu	3-hour
CO	Proper Design/Operation	400 ppmvd at 3% O_2[2]	30-day rolling
NO_x	Low NO_x Burner and Flue Gas Recirculation	0.11 lb/MMBtu	30-day rolling
Pb	Natural Gas combustion	N/A	N/A

[1] PM/PM_{10} rate based on 112(g) analysis will be set at 0.004 lb/MMBtu
[2] CO rate based on 112(g) analysis will be set at 0.036 lb/MMBtu

BACT Evaluation for Cooling Tower

PM/PM_{10} are emitted from cooling towers because the water circulating in the tower contains small amounts of dissolved solids (e.g., calcium, magnesium, etc.) that crystallize and form airborne particles as the water drift leaves the cooling tower. AP-42 Section 13.4 Wet Cooling Towers (1/95) PM_{10} emission factors are extremely conservative because most of the drift droplets will remain in liquid form until they reach the ground due to gravity. Advances in drift eliminator technology have greatly reduced the potential for cooling tower drift.

Drift eliminators will minimize particulate emissions from the cooling towers. Drift eliminators are designated as BACT for each cooling tower in the RBLC database. The RBLC presents a wide range of emission rates for cooling towers due to differences in type and operating characteristics. SWEPCO proposes high-efficiency drift eliminators as BACT for particulate emissions from the cooling towers with a drift rate of 0.001%. ADEQ has determined that a drift rate of 0.0005% is BACT.

Cooling Tower		
Pollutant	*Control Technology Determination*	*BACT Limit*
PM	High-efficiency drift eliminators	Drift rate of 0.0005%

BACT Evaluations for Diesel-Fired Emergency Generator and Fire Pump Engine

SWEPCO will construct and operate a diesel-fired emergency generator with a nominal power output capacity of 2 MW (2,682 hp) and two diesel-fired fire pump engines with a nominal power output capacity of 300 hp each. These sources will be operated for testing and emergencies only: operation of the emergency generator will not exceed 500 hours per year and operation of the fire pump engines will not exceed a total of 100 hours per year. EPA's RBLC was queried to identify controls for other similar-sized (between 0.5 and 5 MW) emergency generators and other fire pump diesel engines. The RBLC shows that no add-on controls have been installed for emergency generators or fire pump engines. That is, BACT for all pollutants for emergency generators and fire pump engines is a combination of proper design and operation (including one or all of ignition timing retard, turbo-charging, and after cooling), fuel specification (i.e. low-sulfur diesel), and operation limitations. Additionally, the RBLC shows that most emergency generators and fire pump engines have BACT/permit limits at or above the recently promulgated NSPS Subpart IIII. SWEPCO proposes the NSPS Subpart IIII limits as BACT for emissions of NO_x+NMHC, CO, and PM, as applicable. The proposed SO_2 limit is based on the use of low-sulfur (15 ppm) diesel fuel as required by NSPS Subpart IIII. The proposed BACT limits for the emergency generator and fire pump engine are summarized below.

Emergency Generator and Fire Pump Engines		
Pollutant	*Control Technology Determination*	*BACT Limit (g/kWh)*
NO_x + NMHC	Proper Design/Operation Fuel Specification – Low Sulfur Diesel Operation Limitation – 100 hrs/yr Fire Pump Engine 500 hrs/yr Emergency Generator	6.4
SO_2		0.007
PM		0.2
CO		3.5

BACT Evaluation for Material Transfer/Storage Operations

Particulate emissions will be generated by transport and storage of coal, lime, and fly ash/FGD waste. Based on a review of the RBLC database, the most stringent technologies for controlling

PM from such operations are forced-air dust collection (i.e., fabric filters or baghouses) and natural draft dust collection (i.e., bin vents). Where feasible, fabric filters or bin vents will be used to control PM emissions from major material handling silos and transfer points with a minimum control rate of 99 percent. Elsewhere, SWEPCO proposes to use currently accepted best industry practices for PM control, including the use of water and/or chemical suppressants and enclosures for buildings and conveyors.

112(g) Case by Case MACT

Section 112(g) of the Clean Air Act requires that the permitting authority determine a MACT emission limitation on a case-by-case basis for newly constructed major sources of HAPs for which no federal emission limitation has been promulgated. The SWEPCO facility will be a new major source for HAPs and is therefore required to undergo a case-by-case MACT determination.

Since SWEPCO is a new source of HAP, under 63.43,

> *The MACT emission limitation or MACT requirements recommended by the applicant and approved by the permitting authority shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source, as determined by the permitting authority*
>
> *and*
>
> *Based upon available information, as defined in this subpart, the MACT emission limitation and control technology (including any requirements under paragraph (d)(3) of this section) recommended by the applicant and approved by the permitting authority shall achieve the maximum degree of reduction in emissions of HAP which can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.*

This limits HAPs from the main boiler, SN-01 as well as the auxiliary boiler, SN-02. A summary of the emission rates follows.

Main Boiler, SN-01

Pollutant	Emission Limit	Averaging Time	Monitoring/Compliance
Mercury	1.7 lb/TBtu	12 month average	Continuous Emission Monitor
Lead	0.000016 lb/MMBtu	3-hour average	Annual Stack Test
Particulate HAPs as	0.012 lb/MMBtu	3-hour average	Annual Stack Test

PM_{10} (filterable):			
Particulate HAPs as PM_{10} (total)	0.025 lb/MMBtu	3-hour average	Annual Stack Test
Hydrogen Chloride	0.0006 lb/MMBtu	3-hour average	Annual Stack Test
Hydrogen Fluoride	0.0002 lb/MMBtu	3-hour average	Annual Stack Test
Organic HAPs as VOC	0.00078 lb/MMBtu[1]	3-hour average	Annual Stack Test

[1] Reduced from draft 112(g) permit proposed limit of 0.0025 lbs/**MMBtu**

Auxiliary Boiler, SN-02

Pollutant	Emission Limit	Averaging Time	Monitoring/Compliance
Inorganic HAPs as PM_{10} (total)	0.004 lb/MMBtu	3-hour average	Initial Stack Test
Organic HAPs as CO	0.036 lb/MMBtu	3-hour average	Initial Stack Test

Regulations

The following table contains the regulations applicable to this permit.

Regulations
Arkansas Air Pollution Control Code, Regulation 18, effective February 15, 1999
Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective May 28, 2006
Regulations of the Arkansas Operating Air Permit Program, Regulation 26, effective September 26, 2002
40 CFR Part 52.21, Prevention of Significant Deterioration (PSD)
40 CFR Part 60, Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978*
40 CFR Subpart Db--*Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*
40 CFR Part 60, Subpart Y, *Standards of Performance for Coal Preparation Plants*
40 CFR Part 60, Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*
40 CFR Part 63, Subpart ZZZZ, *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

Emission Summary

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	188.2	801.56
		PM_{10}	172.0	732.26
		SO_2	480.5	2102.69
		VOC	15.3	23.08
		CO	937.3	3951.0
		NO_X	512.6	1336.6

HAPs		Acetaldehyde*	0.25	0.96
		Acrolein*	0.13	0.5
		Antimony**	0.15	0.66
		Arsenic**	0.52	2.25
		Benzene*	0.53	2.17
		Benzyl Chloride*	0.27	1.15
		Beryllium**	0.02	0.08
		1,3-Butadiene*	0.02	0.02
		Cadmium**	0.03	0.09
		Carbon Disulfide	0.05	0.22
		Chloroform*	0.03	0.1
		Chromium**	0.19	0.77
		Chromium VI**	0.06	0.23
		Cobalt**	0.04	0.13
		Cyanide**	0.94	4.11
		Dichlorobenzene*	0.01	0.01
		Dimethyl Sulfate*	0.02	0.08
		Dioxins & Furans	0.01	0.01
		Formaldehyde*	0.18	0.44
		Hexane*	0.13	0.41
		Hydrogen Chloride	3.6	15.77
		Hydrogen Fluoride	1.2	5.26
		Lead**	0.097	0.42
		Manganese**	1.12	4.81
		Mercury	0.0102	0.0447
		Methylhydrazine*	0.07	0.28
		Nickel**	0.12	0.47
		Phenol*	0.01	0.03
		Phosphorous**	2.4	10.51
		POM*	0.04	0.07
		Propionaldehyde*	0.15	0.63
		Selenium**	0.25	1.06
		Sulfuric Acid	25.2	110.38
		Toluene*	0.02	0.02
		Xylene*	0.02	0.02
Air Contaminants ***		Ammonia	37.5	164.4
SN	Description	Pollutant	lb/hr	tpy
01	Main Boiler	PM	150.0	657.0
		PM_{10}	150.0	657.0
		SO_2	480.0	2102.4
		VOC	4.7	20.5
		CO	900.0	3,942.0
		NO_x	420.0	1,314.0
		Acetaldehyde*	0.22	0.94

		Acrolein*	0.11	0.48
		Antimony**	0.15	0.66
		Arsenic**	0.51	2.24
		Benzene*	0.49	2.14
		Benzyl Chloride*	0.27	1.15
		Beryllium**	0.01	0.04
		Cadmium**	0.02	0.08
		Carbon Disulfide	0.05	0.22
		Chloroform*	0.03	0.1
		Chromium**	0.18	0.76
		Chromium VI**	0.06	0.23
		Cobalt**	0.03	0.12
		Cyanide**	0.94	4.11
		Dimethyl Sulfate*	0.02	0.08
		Dioxins & Furans	0.01	0.01
		Formaldehyde*	0.09	0.4
		Hexane*	0.03	0.11
		Hydrogen Chloride	3.6	15.8
		Hydrogen Fluoride	1.2	5.3
		Lead**	0.096	0.42
		Manganese**	1.11	4.8
		Mercury	0.0102	0.0447
		Methylhydrazine*	0.07	0.28
		Nickel**	0.11	0.46
		Phenol*	0.01	0.03
		Phosphorous**	2.4	10.51
		POM*	0.01	0.04
		Propionaldehyde*	0.15	0.63
		Selenium**	0.24	1.05
		Sulfuric Acid	25.2	110.4
		Ammonia***	37.5	164.4
02	Auxiliary Boiler	PM	2.3	0.6
		PM_{10}	2.22	0.55
		SO_2	0.4	0.1
		VOC	3.0	0.8
		CO	20.0	5.0
		NO_x	61.1	15.3
		Arsenic**	0.01	0.01
		Benzene*	0.01	0.01
		Beryllium**	0.01	0.01
		Cadmium**	0.01	0.01
		Chromium**	0.01	0.01
		Cobalt**	0.01	0.01
		Dichlorobenzene*	0.01	0.01
		Formaldehyde*	0.05	0.02

		Hexane* Lead** Manganese** Mercury Nickel** POM* Selenium**	0.1 0.01 0.01 0.00014 0.01 0.01 0.01	0.3 0.01 0.01 0.000035 0.01 0.01 0.01
03	Emergency Diesel Generator	PM PM_{10} SO_2 VOC CO NO_x 1,3-Butadiene* Acetaldehyde* Acrolein* Benzene* Formaldehyde* POM* Toulene* Xylene*	0.9 0.9 0.1 6.8 15.5 28.3 0.01 0.02 0.01 0.02 0.03 0.01 0.01 0.01	0.3 0.3 0.1 1.7 3.9 7.1 0.01 0.01 0.01 0.01 0.01 0.01 0.01 0.01
04	Fire Pump Diesel Engines	PM PM_{10} SO_2 VOC CO NO_x 1,3-Butadiene* Acetaldehyde* Acrolein* Benzene* Formaldehyde* POM* Toluene* Xylene*	0.1 0.1 0.1 0.8 1.8 3.2 0.01 0.01 0.01 0.01 0.01 0.01 0.01 0.01	0.1 0.1 0.1 0.04 0.1 0.2 0.01 0.01 0.01 0.01 0.01 0.01 0.01 0.01
EP-01	Coal Dumper Tunnel Exhaust Fan	PM PM_{10}	0.1 0.1	0.3 0.2
EP-02	Material Transfer (C-1 to C-3)	PM PM_{10}	0.3 0.2	1.0 0.5
EP-03	Material Transfer (C-1 to lowering well 1)	PM PM_{10}	0.3 0.2	1.0 0.5
EP-04	Material Transfer (C-3 to lowering well 2)	PM PM_{10}	0.3 0.2	1.0 0.5
EP-05	Coal Reclaim Tunnel Exhaust Fan	PM PM_{10}	0.1 0.1	0.3 0.2

EP-06	Coal Reclaim Tunnel Exhaust Fan	PM PM_{10}	0.1 0.1	0.3 0.2
EP-07	Coal Crusher House Exhaust Fan	PM PM_{10}	0.1 0.1	0.3 0.3
EP-08	Coal Crusher House Exhaust Fan	PM PM_{10}	0.1 0.1	0.3 0.2
EP-09	Coal Sample House Exhaust Fan	PM PM_{10}	0.1 0.1	0.1 0.1
EP-10	Coal Silo Wet Scrubber	PM PM_{10}	1.8 1.8	7.6 7.6
EP-15	Lime Vacuum Conveyor Exhauster	PM PM_{10}	0.3 0.3	1.2 1.2
EP-16	Lime Vacuum Conveyor (Railcar Unloading) Exhauster	PM PM_{10}	0.3 0.3	1.2 1.2
EP-17	Lime Silo Bin Vent Filter	PM PM_{10}	0.2 0.2	0.6 0.6
EP-18	Lime Day Bin Vent Filter	PM PM_{10}	0.2 0.2	0.6 0.6
EP-19	Lime Day Bin Vent Filter	PM PM_{10}	0.2 0.2	0.6 0.6
EP-20	Activated Carbon Bin Vent Filter	PM PM_{10}	0.2 0.2	0.7 0.7
EP-21	Fly Ash Waste Silo Bin Vent Filter	PM PM_{10}	0.2 0.2	0.6 0.6
EP-22	Fly Ash Recycle Bin Vent Filter	PM PM_{10}	0.2 0.2	0.6 0.6
EP-23	Fly Ash/FGD Vac Conveyor (to Waste Silo) Exhauster	PM PM_{10}	0.3 0.3	1.2 1.2
EP-24	Fly Ash/FGD Vac Conveyor (to Recycle Silo) Exhauster	PM PM_{10}	0.3 0.3	1.2 1.2
TP-11	Coal Crusher House Surge Bin Vent Filter	PM PM_{10}	0.1 0.1	0.4 0.4
TP-12	Coal Crusher House Bin Vent Filter	PM PM_{10}	0.1 0.1	0.4 0.4
TP-18	Material Transfer (C-6A to C-7A)	These Sources Vent to SN-EP-10		
TP-19	Material Transfer (C-6B to C-7B)			
TP-20	Material Transfer (C-7A to storage silos)			
TP-21	Material Transfer (C-7B to storage silos)			
TP-22	Material Transfer (Fly Ash/FGD Waste to Truck)	PM PM_{10}	0.1 0.1	0.2 0.1

TP-23	Fly Ash Disposal to Landfill	PM PM_{10}	0.1 0.1	0.2 0.1
F-01	Active Coal Pile	PM PM_{10}	0.2 0.1	0.8 0.4
F-02	Active Coal Pile	PM PM_{10}	0.2 0.1	0.8 0.4
F-03	Dozing Coal – Active and Inactive Pile	PM PM_{10}	2.1 0.4	9.4 1.5
F-04	Inactive Coal Pile	PM PM_{10}	2.3 1.2	10.1 5.1
F-05	Dozing of Solid Waste Disposal Area	PM PM_{10}	10.7 3.3	46.9 14.3
F-06	Solid Waste Disposal Storage	PM PM_{10}	4.4 1.6	19.0 6.7
CT-01	Cooling Tower	PM PM_{10}	5.2 5.2	22.8 22.8
RD-01	Roads	PM PM_{10}	3.8 1.1	11.9 3.3

*HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.
**HAPs included in the PM totals.
***Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.

SECTION III: PERMIT HISTORY

This is the initial permit for this facility.

SECTION IV: SPECIFIC CONDITIONS

SN-01
Main Boiler

Source Description

An ultra-supercritical pulverized coal (PC) boiler (600 MW) produces steam at temperatures above 1100 °F to drive a condensing steam turbine to generate electricity. The PC boiler burns sub-bituminous coal as the main fuel and uses natural gas for startup and flame stabilization.

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with the SO_2, CO and NO_x limits through use of Continuous Emission Monitors (CEM) required in Specific Conditions 11 and 12 . Compliance with the PM_{10}, VOC, Pb and Sulfuric Acid (H_2SO_4) limits shall be demonstrated through compliance with the testing requirements of Specific Condition 7 . [Regulation 19, §19.901 et seq., effective October 15, 2007 and 40 CFR Part 52, Subpart E, Regulation 19, §19.304 and 40 CFR 63.43]

Pollutant	lb/hr	tpy
PM_{10}	150.0	657.0
SO_2	480.0	2102.4
VOC	4.7	20.5
CO	900.0	3,942.0
NO_x	420.0	1,314.0
Pb (Lead)*	0.096	0.42
Sulfuric Acid (H_2SO_4)	25.2	110.4

*emission rate also included in PM_{10} emission rate

2. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with the PM emission rate through compliance with Specific Condition 7. Compliance with the Mercury emission limits shall be demonstrated through the use of CEM required in Specific Condition 13. Hydrogen Chloride and Hydrogen Fluoride emission rates shall be demonstrated through compliance with Specific Condition 8. Compliance with the emission rates for the other compounds listed shall be demonstrated through compliance with Specific Condition 10. [Regulation No. 19 §19.304 and 40 CFR 63 and Regulation 18, §18.801, effective

February 15, 1999, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	150	657
Acetaldehyde*	0.22	0.94
Acrolein*	0.11	0.48
Antimony**	0.15	0.66
Arsenic**	0.51	2.24
Benzene*	0.49	2.14
Benzyl Chloride*	0.27	1.15
Beryllium**	0.01	0.04
Cadmium**	0.02	0.08
Carbon Disulfide	0.05	0.22
Chloroform*	0.03	0.1
Chromium**	0.18	0.76
Chromium VI**	0.06	0.23
Cobalt**	0.03	0.12
Cyanide**	0.94	4.11
Dimethyl Sulfate*	0.02	0.08
Dioxins & Furans*	0.01	0.01
Formaldehyde*	0.09	0.4
Hexane*	0.03	0.11
Hydrogen Chloride	3.6	15.77
Hydrogen Fluoride	1.2	5.26
Manganese**	1.11	4.8
Mercury	0.0102***	0.0447
Methylhydrazine*	0.07	0.28
Nickel**	0.11	0.46
Phenol*	0.01	0.03
Phosphorous**	2.4	10.51
POM**	0.01	0.04
Propionaldehyde*	0.15	0.63
Selenium**	0.24	1.05

* Included in the VOC total
** Included in the PM total
*** Annual average

3. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the emission rates shall be demonstrated through compliance with Specific Condition 9. [Regulation 18, §18.801, effective February 15, 1999, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
Ammonia	37.5	164.4

4. The permittee shall not discharge into the atmosphere from SN-01 gases which exhibit an opacity greater than 10% (6-minute average) except for one 6-minute period per hour (during any 60 minute consecutive period) of not more than 27% as measured using EPA Reference Method 9. Compliance with this condition shall be demonstrated by comparison of the limit to the 6-minute average opacity reading obtained from the COMS installed in accordance with Specific Condition 11. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

5. The permittee shall not exceed the BACT emission limits set forth in the following table. Compliance with SO_2, CO and NO_x emission rates shall be demonstrated by use of CEMs required in Specific Conditions 11and 12. Compliance with other limits shall be demonstrated by the testing requirements of Specific Condition 7. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	*BACT Limit*	*Averaging period*
PM/ PM_{10} (filterable)	0.012 lb/MMBtu	3-hour
PM_{10} (total)	0.025 lb/MMBtu	3-hour
SO_2	0.08 lb/MMBtu While combusting coal with a sulfur content greater than 0.45% by weight	30-day rolling average
	0.065 lb/MMBtu While combusting coal with a sulfur content less than or equal to 0.45% by weight	30-day rolling average
	480 lbs/hr	24 hour rolling average
VOC	0.0036 lb/MMBtu[1]	3-hour
CO	0.15 lb/MMBtu	30-day rolling
NO_x	0.067 lb/MMBtu for normal operations[2]	24-hour rolling average
	420 lbs/hr	24 hour rolling average

	0.05 lb/MMBtu	Annual average
Pb (Lead)	2.6E-5 lb/MMBtu [3]	3-hour
H_2SO_4 Mist	0.0042 lb/MMBtu	3-hour

[1] VOC rate based on 112(g) analysis will be set at 0.00078 lb/MMBtu
[2] Normal operation is defined as operation at or above 300 MW gross output from the Unit 1 generator
[3] Pb rate based on 112(g) analysis will be set at 1.6 E-05 lb/MMBtu

6. The permittee shall not exceed the emission rates set forth in the following table for SN-01 (Main Boiler). Compliance with the Mercury emission limits shall be demonstrated through use of the CEM required in Specific Condition 13. Compliance with other limits shall be demonstrated by the testing requirements of Specific Conditions 7 and 8. [Regulation No. 19 §19.304 and 40 CFR 63]

Pollutant	Emission Limit	Averaging Time
Mercury	1.7 lb/TBtu	12 month average
Lead	0.000016 lb/MMBtu	3-hour average
PM_{10} (filterable)	0.012 lb/MMBtu	3-hour average
PM_{10} (total)	0.025 lb/MMBtu	3-hour average
Hydrogen Chloride	0.0006 lb/MMBtu	3-hour average
Hydrogen Fluoride	0.0002 lb/MMBtu	3-hour average
VOC	0.00078 lb/MMBtu	3-hour average

7. The permittee shall conduct testing at SN-01 to determine the emission rates for PM, PM_{10}, VOC, Pb and Sulfuric Acid (H_2SO_4). This testing shall be performed in accordance with Plantwide Condition 3. This testing shall be repeated on an annual basis. Testing shall be performed in accordance with the methods listed in the following table or a Department approved alternative. A copy of these test results shall be submitted in accordance with General Provision 7. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	EPA Reference Method
PM Filterable and PM_{10} Filterable	5 or 17
PM Total and PM_{10} Total	5 and 202 or 17 and 202
VOC	25 or 25A
Pb	12 or 29
Sulfuric Acid (H_2SO_4)	8 or Controlled Condensate Method

8. The permittee shall conduct testing at SN-01 to determine the emission rates for Hydrogen Chloride and Hydrogen Fluoride. This testing shall be performed in accordance with Plantwide Condition 3. This testing shall be repeated on an annual basis. Testing shall be performed in accordance with the methods listed in the following table or a Department approved alternative. A copy of these test results shall be submitted in accordance with General Provision 7. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	EPA Reference Method
Hydrogen Chloride	26
Hydrogen Fluoride	

9. The permittee shall conduct testing at SN-01 to determine compliance with the emission rate for Ammonia. This testing shall be performed in accordance with Plantwide Condition 3. This testing shall be repeated on an annual basis. Testing shall be performed in accordance with the methods listed in the following table or a Department approved alternative. A copy of these test results shall be submitted in accordance with General Provision 7.

Pollutant	EPA Reference Method
Ammonia	CTM-027

10. The permittee shall conduct an initial test at SN-01 to determine compliance with the emission rates for all other pollutants listed in Specific Condition 2 not otherwise requiring a CEM or specific testing (i.e. all pollutants except PM, Ammonia, Hydrogen Chloride, Hydrogen Fluoride and Mercury). This testing shall be performed in accordance with Plantwide Condition 3. Testing shall be performed in accordance with testing protocols submitted by the applicant and approved by the Department in advance. A copy of these test results shall be submitted in accordance with General Provision 7. [Regulation No. 19 §19.304 and 40 CFR 63 and Regulation 18, §18.801, effective February 15, 1999, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

11. This source is considered an affected source under 40 CFR Part 60, Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978,* and is subject, but not limited to, the following conditions. [Regulation 19, §19.304 and 40 CFR Part 60, Subpart Da]

a) On and after the date the particulate matter performance test required to be conducted under 40 CFR 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

b) On and after the date on which the performance test required to be conducted under 40 CFR 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification is commenced after February 28, 2005, except for modified affected facilities meeting the requirements of paragraph (d) of 40 CFR 60.42Da, any gases that contain particulate matter in excess of either:
    i. 18 ng/J (0.14 lb/MWh) gross energy output; or
    ii. 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

c) On and after the date on which the performance test required to be conducted under 40 CFR 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except as provided for under paragraphs (j) or (k) of 40 CFR 60.43Da, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of CFR 60.43Da(h):
    i. For an affected facility for which construction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:
        1. 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or
        2. 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

d) On and after the date on which the performance test required to be conducted under 40 CFR 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except for an IGCC meeting the requirements of paragraph (f) of this section, any gases that contain nitrogen oxides (expressed as NO_2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of 40 CFR 60.44Da(e):
    i. For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under §60.48Da(k).

e) For each coal-fired electric utility steam generating unit other than an integrated gasification combined cycle (IGCC) electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases which contain mercury (Hg) emissions in excess of each Hg emissions limit in paragraphs (a)(1) through (5) of 40 CFR 60.45Da that applies to you. The Hg emissions limits in paragraphs (a)(1) through (5) 40 CFR 60.45Da are based on a 12-month rolling average using the procedures in §60.50Da(h).

i. For each coal-fired electric utility steam generating unit that burns only sub bituminous coal:
   1. If your unit is located in a county-level geographical area receiving greater than 25 inches per year (in/yr) mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 66 x 10^{-6} lb/MWh or 0.066 lb/GWh on an output basis. The SI equivalent is 0.0083 ng/J.

f) The particulate matter emission standards under 40 CFR 60.42Da, the nitrogen oxides emission standards under 40 CFR 60.44Da, and the Hg emission standards under 40 CFR 60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

g) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:
   i. Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,
   ii. Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and
   iii. Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 million Btu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph (a), (b), (d), (e), and (h) under 40 CFR 60.43Da for any period of operation lasting from 24 hours to 30 days when:
      1. Any one flue gas desulfurization module is not operated, The affected facility is operating at the maximum heat input rate,
      2. The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and
      3. The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

h) After the initial performance test required under 40 CFR 60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under §60.43Da and the nitrogen oxides emission limitations under §60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

i) For the initial performance test required under 40 CFR 60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under 40 CFR 60.43Da and the nitrogen oxides emission limitation under 40 CFR 60.44Da is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

j) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

   i. Compliance with applicable 30-day rolling average SO_2 and NO_x emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_x only), or emergency conditions (SO_2) only.
   ii. Compliance with applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days.
   iii. Compliance with applicable daily average particulate matter emission limitations is determined by calculating the arithmetic average of all hourly emission rates for particulate matter each boiler operating day, except for data obtained during startup, shutdown, and malfunction.

k) If an owner or operator has not obtained the minimum quantity of emission data as required under §60.49Da of this subpart, compliance of the affected facility with the emission requirements under Secs. 40 CFR 60.43Da and 40 CFR 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19.[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989]

   i. Compliance provisions for sources subject to 40 CFR 60.44Da(d)(1), (e)(1), or (f). The owner or operator of an affected facility subject to 40 CFR 60.44Da(d)(1) or (e)(1) shall calculate NO_x emissions by multiplying the average hourly NO_x output concentration, measured according to the provisions of 40 CFR 60.49Da(c), by the average hourly flow rate, measured according to the provisions of 40 CFR 60.49Da(l), and dividing by the average hourly gross energy output, measured according to the provisions of 40 CFR 60.49Da(k).

l) As an alternative to meeting the compliance provisions specified in paragraph (o) of 40 CFR 60.47Da, an owner or operator may elect to install, certify, maintain, and operate a continuous emission monitoring system measuring particulate matter emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of 40 CFR 60.47Da.

i. The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a continuous monitoring system measuring particulate matter. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of 40 CFR 60.47Da by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.
ii. Each continuous emission monitor shall be installed, certified, operated, and maintained according to the requirements in 40 CFR 60.49Da(v).
iii. The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under 40 CFR 60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph 40 CFR 60.47Da (p)(1) of this section, whichever is later.
iv. Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19, section 4.1.
v. At a minimum, valid continuous monitoring system hourly averages shall be obtained for 90 percent of all operating hours on a 30-day rolling average.
    1. At least two data points per hour shall be used to calculate each 1-hour arithmetic average.
    2. Reserved]
vi. The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/h, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under 40 CFR 60.13(e)(2) of subpart A of this part.
vii. All valid continuous monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph 40 CFR 60.48Da (j)(5) are not met.
viii. When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 90 percent of all operating hours per 30-day rolling average.

m) Except as provided for in paragraphs (t) and (u) of 40 CFR 60.49Da, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

n) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

    i. Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.
    ii. For a facility that qualifies under the numerical limit provisions of 40 CFR 60.43Da(d), (i), (j), or (k) sulfur dioxide emissions are only monitored as discharged to the atmosphere.
    iii. An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required under paragraph (b)(1) of 40 CFR 60.49Da.

o) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or

    ii. If the owner or operator has installed a nitrogen oxides emission rate continuous emission monitoring system (CEMS) to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of 40 CFR 60.49Da, except that the owner or operator shall also meet the requirements of 40 CFR 60.51Da. Data reported to meet the requirements of 40 CFR 60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

p) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

q) The continuous monitoring systems under paragraphs (b), (c), and (d) of this 40 CFR 60.49Da(e) are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

r) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of 40 CFR 60.49Da.

s) The 1-hour averages required under paragraph 40 CFR 60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under §60.48Da. The 1-hour averages are calculated using the data points required under 40 CFR 60.13(b). At least two data points must be used to calculate the 1-hour averages.

t) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (1) through (6) 40 CFR 60.49Da.

    i. Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (e.g., on or downstream of the last control device);
    ii. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;
    iii. Performance evaluation procedures and acceptance criteria (e.g., calibrations, relative accuracy test audits (RATA), etc.);
    iv. Ongoing operation and maintenance procedures in accordance with the general requirements of 40 CFR 60.13(d) or part 75 of this chapter (as applicable);
    v. Ongoing data quality assurance procedures in accordance with the general requirements of 40 CFR 60.13 or part 75 of this chapter (as applicable); and
    vi. Ongoing record keeping and reporting procedures in accordance with the requirements of this subpart.

u) For sulfur dioxide, nitrogen oxides, particulate matter, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

v) The owner or operator of an affected facility subject to the emissions limitations in 40 CFR 60.45Da or 40 CFR 60.46Da shall provide notifications in accordance with §60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of Sec.60.7(f).

12. The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) for SN-01 and record the output of the system to measure CO. The CEMS shall comply with the Department "Continuous Emissions Monitoring

Systems Conditions." The CEMS data may be used by the Department for enforcement purposes. [Regulation 19, §19.702 et seq, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

13. The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) for SN-01 and record the output of the system to measure Mercury (Hg). The CEMS shall comply with the attached Department "Continuous Emissions Monitoring Systems Conditions", attached. The CEMS data may be used by the Department for enforcement purposes. [Regulation 19, §19.702 et seq, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

14. The permittee shall maintain monthly records of the average lb/MMBtu mercury emission rate. These records shall include the average rate for the preceding consecutive 12 month period. These records shall be updated by the 15th day of the month after the month which the records represent, be kept on site, and be made available to Department personnel upon request. Reports of these records shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 70.6]

15. The permittee must install and continuously operate a bag leak detection system for SN-01. [Regulation 19, §19.705 and 40 CFR 70.6]

a) The bag leak detection system must be certified by the manufacturer to be capable of continuously detecting and recording particulate matter emissions at concentrations of 1.0 milligrams per actual cubic meter;
b) The bag leak detection system shall provide output of relative or absolute particulate matter loadings;
c) The bag leak detection system shall be equipped with an alarm system that will sound an audible alarm when an increase in relative particulate loadings is detected over a preset level;
d) The bag leak detection system shall be installed and operated in a manner consistent with available written guidance from the U.S. Environmental Protection Agency or, in the absence of such written guidance, the manufacturer's written specifications and recommendations for installation, operation, and adjustment of the system;
e) The initial adjustment of the system shall, at a minimum, consist of establishing the baseline output by adjusting the sensitivity (range) and the averaging period of the device, and establishing the alarm set points and the alarm delay time;
f) Following initial adjustment, the permittee must not adjust the sensitivity or range, averaging period, alarm set points, or alarm delay time, except as detailed in the operation and maintenance plan required. The permittee must not increase the sensitivity by more than 100 percent or decrease the sensitivity by more than 50 percent over a 365 day period unless such adjustment follows a complete fabric filter inspection which demonstrates the fabric filter is in good operating condition.

16. The permittee shall establish an operating and maintenance plan that specifies the procedures to follow in the case of a bag leak detection system alarm or malfunction. The corrective measures plan must include, at a minimum, the procedures used to determine and record the time and cause of the alarm or bag leak detection system malfunction as

well as the corrective measures taken to correct the control device or bag leak detection system malfunction or to minimize emissions.

a) The procedures used to determine the cause of the alarm or bag leak detection system malfunction must be initiated within 30 minutes of the time the alarm first sounds; and
b) The cause of the alarm or bag leak detection system malfunction must be alleviated by taking the necessary corrective measure(s) which may include, but are not to be limited to, the following:
c) Inspecting the fabric filter for air leaks, torn or broken filter elements, or any other malfunction that may cause an increase in emissions;
d) Sealing off defective bags or filter media;
e) Replacing defective bags or filter media, or otherwise repairing the control device;
f) Sealing off a defective fabric filter compartment;
g) Cleaning the bag leak detection system probe, or otherwise repairing the bag leak detection system; or
h) Shutting down the boiler.

17. The permittee shall maintain records of hourly bag leak detector readings. These records shall be updated by the 15th day of the month after the month which the records represent, be kept on site, and be made available to Department personnel upon request. Reports of these records shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 70.6]

18. The permittee shall not exceed a 24 hour rolling average heat input to SN-01 of 6000 MMBtu. [Regulation 19, §19.901 et seq. and A.C.A.§8-4-203 as referenced by A.C.A.§8-4-304, and 40 CFR 70.6]

19. The permittee shall maintain hourly and 24 hour records of the heat input to SN-01. These records shall be updated by the 15th day of the month after the month which the records represent, be kept on site, and be made available to Department personnel upon request. Reports of these records shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 70.6]

20. The permittee shall maintain records of coal sulfur weight percent combusted in SN-01 on a 30 day rolling average. These records shall be updated by the 15th day of the month after the month which the records represent, be kept on site, and be made available to Department personnel upon request. Reports of these records shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 70.6]

21. The permittee shall maintain records of the following averages. These records shall be updated by the 15th day of the month after the month which the records represent, be kept on site, and be made available to Department personnel upon request. Reports of these records shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 70.6]

Pollutant	Rate	Averaging Period
SO_2	lb/MMBtu	30-day rolling average
	lb/hr	24-hour rolling average
NO_x	lb/MMBtu for normal operations [1]	24-hour rolling average
	lbs/hr	24 hour rolling average
	lb/MMBtu	12 month rolling average
CO	lb/MMBtu	30-day rolling average
Mercury	lb/TBtu	12 month rolling average

[1] Normal operation is defined as operation at or above 300 MW gross output from the Unit 1 generator

Acid Rain Program

22. The affected unit (SN-01) is subject to and shall comply with applicable provisions of the Acid Rain Program (40 CFR Parts 72, 73, and 75).

23. The submission of the NO_X, SO_2, and O_2 or CO_2 monitoring plan is required at least 45 days prior to the CEMS certification testing. Notice of CEMS certification testing is required at least 21 days prior to the CEMS certification testing. [40 CFR Part 75-Continuous Emission Monitoring Subpart G]

24. The initial NO_X, and O_2 or CO_2 CEMS certification testing is to occur no later than 90 days after the unit commences commercial operation except the testing must occur prior to the date this unit is declared commercial in accordance with DOE Form EIA-860. [40 CFR Part 75 Subpart A]

25. The permittee shall ensure that the continuous emissions monitoring systems are in operation and monitoring all unit emissions at all times, except during periods of calibration, quality assurance, preventative maintenance or repair. [40 CFR §75.10]

SN-02
Auxiliary Boiler

Source Description

A natural gas-fired auxiliary boiler (555 MMBtu/hr) is used during startup of the PC boiler.

Specific Conditions

26. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Conditions 31 and 34. [Regulation 19, §19.901 et seq., effective October 15, 2007 and 40 CFR Part 52, Subpart E, Regulation 19, §19.304 and 40 CFR 63.43]

Pollutant	lb/hr	tpy
PM_{10}	2.3	0.6
SO_2	0.4	0.1
VOC	3.0	0.8
CO	20.0	5.0
NO_x	61.1	15.3

27. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Conditions 31 and 34. [Regulation 19, §19.901 et seq., effective October 15, 2007 and 40 CFR Part 52, Subpart E, Regulation 19, §19.304 and 40 CFR 63.43 and Regulation 18, §18.801, effective February 15, 1999, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	2.22	0.55

Arsenic*	0.01	0.01
Benzene**	0.01	0.01
Beryllium*	0.01	0.01
Cadmium*	0.01	0.01
Chromium*	0.01	0.01
Cobalt*	0.01	0.01
Dichlorobenzene**	0.01	0.01
Formaldehyde**	0.05	0.02
Hexane**	0.1	0.3
Lead*	0.01	0.01
Manganese*	0.01	0.01
Mercury	0.00014	0.000035
Nickel*	0.01	0.01
POM**	0.01	0.01
Selenium**	0.01	0.01

* Included in PM Emissions
** Included in VOC emissions

28. The permittee shall not discharge into the atmosphere from SN-02 gases which exhibit an opacity greater than 10% (6-minute average) as measured using EPA Reference Method 9. Compliance shall be demonstrated through compliance with Specific Condition 34. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

29. The permittee shall not exceed the BACT emission limits set forth in the following table. Compliance shall be demonstrated through compliance with Specific Conditions 31 and 34. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	*BACT Limit*	*Averaging Time*
PM/PM_{10}	0.0076 lb/MMBtu[1]	3-hour
SO_2	0.0006 lb/MMBtu	3-hour
VOC	0.0055 lb/MMBtu	3-hour
CO	400 ppmvd at 3% O_2[2]	30-day rolling
NO_x	0.11 lb/MMBtu	30-day rolling
Pb	N/A	N/A

[1] PM/PM_{10} rate based on 112(g) analysis will be set at 0.004 lb/MMBtu
[2] CO rate based on 112(g) analysis will be set at 0.036 lb/**MMBtu**

30. The permittee shall not exceed the emission rates set forth in the following table for SN-02 (Auxiliary Boiler). Compliance with the limits shall be demonstrated through compliance with Specific Condition 31. [Regulation No. 19 §19.304 and 40 CFR 63]

Pollutant	Emission Limit	Averaging Time
PM_{10} (total)	0.004 lb/MMBtu	3-hour average
CO	0.036 lb/MMBtu	3-hour average

31. The permittee shall conduct an initial test at SN-02 to determine lb/hr and lb/MMBtu emission rates for PM_{10} (total) and CO. This testing shall be performed in accordance with Plantwide Condition 3. Testing shall be performed in accordance with the methods listed in the following table or a Department approved alternative. A copy of these test results shall be submitted in accordance with General Provision 7. [Regulation No. 19 §19.304 and 40 CFR 63]

Pollutant	EPA Reference Method
PM_{10}	5 and 202
CO	10

32. The auxiliary boiler, SN-02, shall not be operated in excess of 272.1 MMscf of natural gas during any consecutive 12 month period. Compliance with this condition will be demonstrated by the operational records maintained pursuant to Specific Condition 33. [Regulation 19, §19.901 et seq. and A.C.A.§8-4-203 as referenced by A.C.A.§8-4-304, and 40 CFR 70.6]

33. The permittee shall maintain monthly records of the fuel used in the auxiliary boiler, SN-02. These records shall include the fuel used each month and the fuel used in the previous consecutive 12 month period. These records shall be updated by the 15th day of the month after the month which the records represent, be kept on site, and be made available to Department personnel upon request. Reports of these records shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 70.6]

34. The permittee shall only combust natural gas as fuel in the auxiliary boiler, SN-02. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

35. SN-02 is subject to the provisions of 40 CFR Subpart Db--Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, including but not limited to the following:

a) 40 CFR 60.44b(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO_2 in excess of the following emission limits:

Fuel/Steam generating unit type	Nitrogen oxide emission limits ng/J (lb/million Btu) (expressed as NO_2) heat input
(1) Natural gas and distillate oil,	
(ii) High heat release rate....................	86 (0.20)

b) 40 CFR 60.44b(h) For purposes of paragraph (i) of this section, the nitrogen oxide standards under this section apply at all times including periods of startup, shutdown, or malfunction.

c) 40 CFR 60.44b(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

d) 40 CFR 60.44b (j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a Federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil and a nitrogen content of 0.30 weight percent or less.

e) 40 CFR 60.44b(l) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility which commenced construction, modification, or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO_2) in excess of the following limits:

(1) If the affected facility combusts coal, oil, or natural gas, or a mixture of these fuels, or with any other fuels: A limit of 86 ng/J (0.20 lb/million Btu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input from the combustion of all fuels, a limit determined by use of the following formula:

En = [(0.10 * Hgo)+(0.20 * Hr)]/(Hgo+Hr)

Where:

En is the NO_x emission limit, (lb/million Btu),
Hgo is the heat input from combustion of natural gas or distillate oil, and
Hr is the heat input from combustion of any other fuel.
(3) After February 27, 2006, units may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of Sec. 60.46a (i)(1), and must monitor emissions according to Sec. 40 CFR 60.47a(c)(1), (c)(2), (k), and (l).

f) 40 CFR 60.46b(c) Compliance with the nitrogen oxides emission standards under § 60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

g) 40 CFR 60.46b(e) To determine compliance with the emission limits for nitrogen oxides required under § 60.44b, the owner or operator of an affected facility shall conduct the performance test as required under § 60.8 using the continuous system for monitoring nitrogen oxides under § 60.48(b).

(1) For the initial compliance test, nitrogen oxides from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the nitrogen oxides emission standards under § 60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.
(3) Following the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility which has a heat input capacity greater than 73 MW (250 million Btu/hour) and which combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the nitrogen oxides standards under § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly nitrogen oxides emission data for the preceding 30 steam generating unit operating days.
(4) Following the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility which has a heat input capacity of 73

MW (250 million Btu/hour) or less and which combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the nitrogen oxides standards under § 60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, nitrogen oxides emissions data collected pursuant to § 60.48b(g)(1) or § 60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the nitrogen oxides emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly nitrogen oxides emission data for the preceding 30 steam generating unit operating days.

h) 40 CFR 60.46b (g) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method described in sections 5 and 7.3 of the ASME Power Test Codes 4.1 (see IBR § 60.17(h)). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of § 60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of § 60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

i) 40 CFR 60.46b(h) The owner or operator of an affected facility described in § 60.44b(j) that has a heat input capacity greater than 73 MW (250 million Btu/hour) shall:

(1) Conduct an initial performance test as required under § 60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the nitrogen oxides emission standards under § 60.44b using Method 7, 7A, 7E, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the nitrogen oxides emission standards under § 60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E, or other approved reference methods.

j) 40 CFR 60.48b(i) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) is not required to install or operate a continuous monitoring system for measuring nitrogen oxides emissions.

k) 40 CFR 60.49b (a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by § 60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility,

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§ 60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i),

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired, and,

l) 40 CFR 60.49b(b) The owner or operator of each affected facility subject to the sulfur dioxide, particulate matter, and/or nitrogen oxides emission limits under §§ 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B. The owner or operator of each affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

m) 40 CFR 60.49b(d) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the recording period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

n) 40 CFR 60.49b(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

o) 40 CFR 60.49b(p) The owner or operator of an affected facility described in § 60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date,

(2) The number of hours of operation, and

(3) A record of the hourly steam load.

p) 40 CFR 60.49b(q) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in § 60.44b(j), the results of any nitrogen oxides emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last nitrogen oxides emission test.

q) 40 CFR 60.49b(w) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

SN-03
Emergency Diesel Generator

Source Description

A 2 MWh diesel-fired emergency generator is used to supply power during outages.

Specific Conditions

36. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Condition 41. [Regulation 19, §19.901 et seq., effective October 15, 2007 and 40 CFR Part 52, Subpart E, Regulation 19, §19.304 and 40 CFR 63.43]

Pollutant	lb/hr	tpy
PM_{10}	0.9	0.3
SO_2	0.1	0.1
VOC	6.8	1.7
CO	15.5	3.9
NO_x	28.3	7.1

37. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Condition 41. [Regulation 19, §19.901 et seq., effective October 15, 2007 and 40 CFR Part 52, Subpart E, Regulation 19, §19.304 and 40 CFR 63.43, and Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	0.9	0.3
1,3-Butadiene	0.01	0.01
Acetaldehyde	0.01	0.01
Acrolein	0.01	0.01
Benzene	0.01	0.01
Formaldehyde	0.01	0.01
POM	0.01	0.01
Toluene	0.01	0.01
Xylene	0.01	0.01

38. This source shall not be operated in excess of 500 hours during any consecutive 12 month period. Compliance with this condition shall be demonstrated by the operational records

maintained pursuant to Specific Condition 39. [Regulation 19, §19.901 et seq. and A.C.A.§8-4-203 as referenced by A.C.A. §8-4-304, and 40 CFR 70.6]

39. The permittee shall maintain monthly records of the hours of operation of this source. These records shall include the hours of operation each month and the hours operated in the previous consecutive 12 month period. These records shall be updated by the 15th day of the month after the month which the records represent, be kept on site, and be made available to Department personnel upon request. Reports of these records shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 70.6]

40. This source is considered an affected source under 40 CFR Part 60, Subpart IIII, *Standards of Performance Stationary Compression Ignition Internal Combustion Engines,* and is subject, but not limited to, the following conditions. [Regulation 19, §19.304 and 40 CFR Part 60, Subpart IIII]

a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of 40 CFR 60.4202.
    i. For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.
b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.
c) Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.
d) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).
e) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.
f) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of this section beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid

for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

g) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

h) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

i) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

j) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (f) of this section after the dates specified in paragraphs (a) through (f) 40 CFR 60.4208.

k) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

l) If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in 40 CFR 60.4211.

    i. If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine.

    ii. If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in 40 CFR 60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

m) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

n) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications.

41. The permittee shall comply with the following emission rates for this source. [Regulation 19, §19.901, 40 CFR Part 52, Subpart E, 40 CFR §60.4202(a)(2) and 40 CFR §§89.112 and 89.113]

Pollutant	Emission Limit
PM	0.20 g/kWh
CO	3.5 g/kWh
NO_x	6.4 g/kWh
NMHC	6.4 g/kWh
Opacity	20% in acceleration mode 15% in Lugging mode 50% during peaks (as measured according to 40 CFR 86, Subpart I)

42. This source is considered an affected source under 40 CFR Part 63, Subpart ZZZZ, *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines,* and is subject, but not limited to, the following conditions. [Regulation 19, §19.304 and 40 CFR Part 63, Subpart ZZZZ]

a) Stationary RICE subject to limited requirements
    i. An affected source which meets either of the criteria in paragraph (b)(1)(i) through (ii) of 40 CFR 63.6590 does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(d).
        1. The stationary RICE is a new or reconstructed emergency stationary RICE
b) If you start up your new or reconstructed stationary RICE on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.
c) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE).

43. The permittee shall conduct a one time visible emissions observation as a method of compliance verification for the opacity limit assigned for this source. This observation shall be conducted by someone trained in EPA Reference Method 9. This observation shall be performed in accordance with Plantwide Condition 3.

    a. If during the observations, visible emissions are detected which appear to be in excess of the permitted opacity limit, the permittee shall:

i. Take immediate action to identify the cause of the visible emissions,
ii. Implement corrective action, and
iii. If excessive visible emissions are still detected, an opacity reading shall be conducted in accordance with EPA Reference Method 9. This reading shall be conducted by a person trained and certified in the reference method. If the opacity reading exceeds the permitted limit, further corrective measures shall be taken.
iv. If no excessive visible emissions are detected, the incident shall be noted in the records as described below.

b. The permittee shall maintain records related to all visible emission observations and Method 9 readings. These records shall be updated on an as-performed basis. These records shall be kept on site and made available to Department personnel upon request. These records shall contain:

i. The time and date of each observation/reading,
ii. The results of the observations,
iii. The cause of any observed exceedance of opacity limits, corrective actions taken, results of the reassessment, and
iv. The name of the person conducting the observation/reading.

[Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

SN-04
Fire Pump Diesel Engines

Source Description

Two small (300 Hp) diesel-fired engines are used to pump water needed for fire suppression. One engine shall serve as a backup and at no time will both operate simultaneously.

Specific Conditions

44. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Condition 48. [Regulation 19, §19.901 et seq., effective October 15, 2007 and 40 CFR Part 52, Subpart E, Regulation 19, §19.304 and 40 CFR 63.43]

Pollutant	lb/hr	tpy
PM_{10}	0.1	0.1
SO_2	0.1	0.1
VOC	0.8	0.04
CO	1.8	0.1
NO_x	3.2	0.2

45. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Condition 48. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	0.1	0.1
1,3-Butadiene	0.01	0.01
Acetaldehyde	0.01	0.01
Acrolein	0.01	0.01
Benzene	0.01	0.01
Formaldehyde	0.01	0.01
POM	0.01	0.01
Toluene	0.01	0.01
Xylene	0.01	0.01

46. The permittee shall not operate these engines for more than a combined total of 100 hours during any consecutive twelve month period. At no time shall both of these engines

operate simultaneously. Compliance shall be demonstrated through compliance with Specific Condition 47. [Regulation 18, §18.1004, Regulation 19, §19.705, 40 CFR Part 70.6 and .C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

47. The permittee shall maintain monthly records of the hours of operation of these engines. These records shall include which engine is operating, the hours of operation each month for each engine and the hours operated in the previous consecutive 12 month period. These records shall be updated by the 15^{th} day of the month after the month which the records represent, be kept on site, and be made available to Department personnel upon request. Reports of these records shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 70.6]

48. This source is considered an affected source under 40 CFR Part 60, Subpart IIII, *Standards of Performance Stationary Compression Ignition Internal Combustion Engines,* and is subject, but not limited to, the following conditions. [Regulation 19, §19.304 and 40 CFR Part 60, Subpart IIII]

a) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants
b) Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.
c) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).
d) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.
e) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of 40 CFR 60.4207 beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.
f) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.
g) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.
h) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (f) of 40 CFR 60.4208 after the dates specified in paragraphs (a) through (f) of 40 CFR 60.4208.

i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.
j) If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.
    i. If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine.
    ii. If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.
k) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.
l) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications.
m) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in 40 CFR 60.4211, is prohibited.

49. The permittee shall comply with the following emission rates for this source. [Regulation 19, §19.304, 40 CFR §60.4202(a)(2) and 40 CFR §§89.112 and 89.113]

Pollutant	Emission Limit
PM	0.20 g/kWh
NO_x	6.4 g/kWh
NMHC	6.4 g/kWh

50. The opacity from this source shall not exceed 20%. Compliance with the opacity standard shall be demonstrated through compliance with Specific Condition 51. [§19.503 of Regulation 19 and 40 CFR Part 52, Subpart E]

51. The permittee shall conduct a one time visible emissions observation as a method of compliance verification for the opacity limit assigned for this source. This observation shall be conducted by someone trained in EPA Reference Method 9. This observation shall be performed in accordance with Plantwide Condition 3.

    a. If during the observations, visible emissions are detected which appear to be in excess of the permitted opacity limit, the permittee shall:

        v. Take immediate action to identify the cause of the visible emissions,
        vi. Implement corrective action, and
        vii. If excessive visible emissions are still detected, an opacity reading shall be conducted in accordance with EPA Reference Method 9. This reading shall be conducted by a person trained and certified in the reference method. If the opacity reading exceeds the permitted limit, further corrective measures shall be taken.
        viii. If no excessive visible emissions are detected, the incident shall be noted in the records as described below.

    b. The permittee shall maintain records related to all visible emission observations and Method 9 readings. These records shall be updated on an as-performed basis. These records shall be kept on site and made available to Department personnel upon request. These records shall contain:

        v. The time and date of each observation/reading,
        vi. The results of the observations,
        vii. The cause of any observed exceedance of opacity limits, corrective actions taken, results of the reassessment, and
        viii. The name of the person conducting the observation/reading.

    [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

SN-EP-01 through EP-10, TP-11 and TP-12 and TP-18 through TP-21
Coal Handling

Source Description

Coal is moved throughout the facility using a series of drops and conveyors.

Specific Conditions

52. The permittee shall not exceed the emission rates set forth in the following table. Emission rates are based on the maximum design operating capacity of the equipment. [Regulation 19, §19.901 et seq., effective October 15, 2007 and 40 CFR Part 52, Subpart E, Regulation 19, §19.304 and 40 CFR 63.43]

SN	Description	Pollutant	lb/hr	tpy
EP-01	Coal Dumper Tunnel Exhaust Fan	PM_{10}	0.1	0.2
EP-02	Material Transfer (C-1 to C-3)	PM_{10}	0.2	0.5
EP-03	Material Transfer (C-1 to lowering well 1)	PM_{10}	0.2	0.5
EP-04	Material Transfer (C-3 to lowering well 2)	PM_{10}	0.2	0.5
EP-05	Coal Reclaim Tunnel Exhaust Fan	PM_{10}	0.1	0.2
EP-06	Coal Reclaim Tunnel Exhaust Fan	PM_{10}	0.1	0.2
EP-07	Coal Crusher House Exhaust Fan	PM_{10}	0.1	0.3
EP-08	Coal Crusher House Exhaust Fan	PM_{10}	0.1	0.2
EP-09	Coal Sample House Exhaust Fan	PM_{10}	0.1	0.1
EP-10	Coal Silo Wet Scrubber	PM_{10}	1.8	7.6
TP-11	Coal Crusher House Bin Vent Filter	PM_{10}	0.1	0.4
TP-12	Coal Crusher House Bin Vent Filter	PM_{10}	0.1	0.4
TP-18	Material Transfer (C-6A to C-7A)	PM_{10}	These sources vent to SN-EP-10	
TP-19	Material Transfer (C-6B to C-7B)	PM_{10}		
TP-20	Material Transfer (C-7A to storage silos)	PM_{10}		
TP-21	Material Transfer (C-7B to storage silos)	PM_{10}		

53. The permittee shall not exceed the emission rates set forth in the following table. Emission rates are based on the maximum design operating capacity of the equipment. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
EP-01	Coal Dumper Tunnel Exhaust Fan	PM	0.1	0.3
EP-02	Material Transfer (C-1 to C-3)	PM	0.3	1.0
EP-03	Material Transfer (C-1 to lowering well 1)	PM	0.3	1.0
EP-04	Material Transfer (C-3 to lowering well 2)	PM	0.3	1.0
EP-05	Coal Reclaim Tunnel Exhaust Fan	PM	0.1	0.3
EP-06	Coal Reclaim Tunnel Exhaust Fan	PM	0.1	0.3
EP-07	Coal Crusher House Exhaust Fan	PM	0.1	0.3
EP-08	Coal Crusher House Exhaust Fan	PM	0.1	0.3
EP-09	Coal Sample House Exhaust Fan	PM	0.1	0.1
EP-10	Coal Silo Wet Scrubber	PM	1.8	7.6
TP-11	Coal Crusher House Bin Vent Filter	PM	0.1	0.4
TP-12	Coal Crusher House Bin Vent Filter	PM	0.1	0.4
TP-18	Material Transfer (C-6A to C-7A)	PM	These sources vent to SN-EP-10	
TP-19	Material Transfer (C-6B to C-7B)	PM		
TP-20	Material Transfer (C-7A to storage silos)	PM		
TP-21	Material Transfer (C-7B to storage silos)	PM		

54. These sources are considered affected sources under 40 CFR Part 60, Subpart Y, *Standards of Performance for Coal Preparation Plants* and shall comply with the following: [Regulation 19, §19.304 and 40 CFR Part 60, Subpart Y]

a) On and after the date on which the performance test required to be conducted by §60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater. [Regulation 19, §19.304 and 40 CFR Part 60, §60.252(c)]

b) Method 9 and the procedures in §60.11 shall be used to determine opacity. [Regulation 19, §19.304 and 40 CFR Part 60, §60.254(b)(2)]

55. The permittee shall use water and surfactant spray systems in the coal handling area to maintain a high coal moisture content in order to minimize uncontrolled dust emissions. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN-TP-22 and TP-23
Material Transfer Points

Source Description

From the storage silos, the fly ash/FGD waste is mixed with water and then drop loaded into open top dump trucks. The dump trucks unload the fly ash/FGD waste to an onsite landfill.

Specific Conditions

56. The permittee shall not exceed the emission rates set forth in the following table. Emission rates are based on the maximum design operating capacity of the equipment. [Regulation 19, §19.901 et seq., effective October 15, 2007 and 40 CFR Part 52, Subpart E, Regulation 19, §19.304 and 40 CFR 63.43]

SN	Description	Pollutant	lb/hr	tpy
TP-22	Material Transfer (Fly Ash/FGD Waste to Truck)	PM_{10}	0.1	0.1
TP-23	Fly Ash Disposal to Landfill	PM_{10}	0.1	0.1

57. The permittee shall not exceed the emission rates set forth in the following table. Emission rates are based on the maximum design operating capacity of the equipment. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
TP-22	Material Transfer (Fly Ash/FGD Waste to Truck)	PM	0.1	0.2
TP-23	Fly Ash Disposal to Landfill	PM	0.1	0.2

58. The opacity from SN-TP-22 shall not exceed 20%. Compliance with the opacity standard shall be demonstrated through compliance with Specific Condition 59. [§19.503 of Regulation 19 and 40 CFR Part 52, Subpart E]

59. Daily visible emission observations shall be used as a method of compliance verification for the opacity limits assigned for these sources. The daily observations shall be conducted by someone familiar with the facility's visible emissions.

    a. If during the observations, visible emissions are detected which appear to be in excess of the permitted opacity limit, the permittee shall:

        i. Take immediate action to identify the cause of the visible emissions,
        ii. Implement corrective action, and

iii. If excessive visible emissions are still detected, an opacity reading shall be conducted in accordance with EPA Reference Method 9 for point sources and in accordance with EPA Method 22 for non-point sources. This reading shall be conducted by a person trained and certified in the reference method. If the opacity reading exceeds the permitted limit, further corrective measures shall be taken.
iv. If no excessive visible emissions are detected, the incident shall be noted in the records as described below.

b. The permittee shall maintain records related to all visible emission observations and Method 9 readings. These records shall be updated on an as-performed basis. These records shall be kept on site and made available to Department personnel upon request. These records shall contain:

i. The time and date of each observation/reading,
ii. The results of the observations,
iii. The cause of any observed exceedance of opacity limits, corrective actions taken, results of the reassessment, and
iv. The name of the person conducting the observation/reading.

[Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

SN-EP-15 through EP-24
Bin Vent Filters and Exhausters

Source Description

Emissions from lime, coal, activated carbon and fly ash storage bins are controlled by filters.

Specific Conditions

60. The permittee shall not exceed the emission rates set forth in the following table. Emission rates are based on the maximum design capacity of the equipment and represent a worst case scenario. Compliance with these emission rates shall be demonstrated through compliance with Plantwide Condition 5. [Regulation 19, §19.901 et seq., effective October 15, 2007 and 40 CFR Part 52, Subpart E, Regulation 19, §19.304 and 40 CFR 63.43]

SN	Description	Pollutant	lb/hr	tpy
EP-15	Lime Vacuum Conveyor Exhauster	PM_{10}	0.3	1.2
EP-16	Lime Vacuum Converyor Exhauster	PM_{10}	0.3	1.2
EP-17	Lime Silo Bin Vent Filter	PM_{10}	0.2	0.6
EP-18	Lime Day Bin Vent Filter	PM_{10}	0.2	0.6
EP-19	Lime Day Bin Vent Filter	PM_{10}	0.2	0.6
EP-20	Activated Carbon Bin Vent Filter	PM_{10}	0.2	0.7
EP-21	Fly Ash Waste Silo Bin Vent Filter	PM_{10}	0.2	0.6
EP-22	Fly Ash Recycle Silo Bin Vent Filter	PM_{10}	0.2	0.6
EP-23	Fly Ash/FGD Vac Conveyor (to Waste Silo) Exhauster	PM_{10}	0.3	1.2
EP-24	Fly Ash/FGD Vac Conveyor (to Recycle Silo) Exhauster	PM_{10}	0.3	1.2

61. The permittee shall not exceed the emission rates set forth in the following table. Emission rates are based on the maximum design capacity of the equipment and represent a worst case scenario. Compliance with these emission rates shall be demonstrated through compliance with Plantwide Condition 5. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
EP-15	Lime Vacuum Conveyor Exhauster	PM	0.3	1.2

EP-16	Lime Vacuum Conveyor Exhauster	PM	0.3	1.2
EP-17	Lime Silo Bin Vent Filter	PM	0.2	0.6
EP-18	Lime Day Bin Vent Filter	PM	0.2	0.6
EP-19	Lime Day Bin Vent Filter	PM	0.2	0.6
EP-20	Activated Carbon Bin Vent Filter	PM	0.2	0.7
EP-21	Fly Ash Waste Silo Bin Vent Filter	PM	0.2	0.6
EP-22	Fly Ash Recycle Silo Bin Vent Filter	PM	0.2	0.6
EP-23	Fly Ash/FGD Vac Conveyor (to Waste Silo) Exhauster	PM	0.3	1.2
EP-24	Fly Ash/FGD Vac Conveyor (to Recycle Silo) Exhauster	PM	0.3	1.2

62. The opacity from these sources shall not exceed 10%. Compliance with the opacity standard shall be demonstrated through compliance with Specific Condition 63. [§19.503 of Regulation 19 and 40 CFR Part 52, Subpart E]

63. Weekly visible emission observations shall be used as a method of compliance verification for the opacity limits assigned for these sources. The weekly observations shall be conducted by someone familiar with the facility's visible emissions.

    a. If during the observations, visible emissions are detected which appear to be in excess of the permitted opacity limit, the permittee shall:

        i. Take immediate action to identify the cause of the visible emissions,
        ii. Implement corrective action, and
        iii. If excessive visible emissions are still detected, an opacity reading shall be conducted in accordance with EPA Reference Method 9. This reading shall be conducted by a person trained and certified in the reference method. If the opacity reading exceeds the permitted limit, further corrective measures shall be taken.
        iv. If no excessive visible emissions are detected, the incident shall be noted in the records as described below.

    b. The permittee shall maintain records related to all visible emission observations and Method 9 readings. These records shall be updated on an as-performed basis. These records shall be kept on site and made available to Department personnel upon request. These records shall contain:

        i. The time and date of each observation/reading,
        ii. The results of the observations,

iii. The cause of any observed exceedance of opacity limits, corrective actions taken, results of the reassessment, and

iv. The name of the person conducting the observation/reading.

[Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

SN-F-01 through F-06
Coal and Solid Waste Piles

Source Description

Coal is stored in outdoor piles prior to its use in the boiler.

Specific Conditions

64. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with the emissions rates for SN-F-01 through SN-F-04 through compliance with Specific Condition 66. Compliance with the emission rates for SN-F05 and F-06 shall be demonstrated through compliance with Specific Condition 67. [Regulation 19, §19.901 et seq., effective October 15, 2007 and 40 CFR Part 52, Subpart E, Regulation 19, §19.304 and 40 CFR 63.43]

SN	Description	Pollutant	lb/hr	tpy
F-01	Active Coal Pile	PM_{10}	0.1	0.4
F-02	Active Coal Pile	PM_{10}	0.1	0.4
F-03	Dozing Coal – Active and Inactive Piles	PM_{10}	0.4	1.5
F-04	Inactive Coal Pile	PM_{10}	1.2	5.1
F-05	Dozing of Solid Waste Disposal Area	PM_{10}	3.3	14.3
F-06	Solid Waste Disposal Area	PM_{10}	1.6	6.7

65. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with the emissions rates for SN-F-01 through SN-F-04 through compliance with Specific Condition 66. Compliance with the emission rates for SN-F05 and F-06 shall be demonstrated through compliance with Specific Condition 67. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
F-01	Active Coal Pile	PM	0.2	0.8
F-02	Active Coal Pile	PM	0.2	0.8
F-03	Dozing Coal – Active and Inactive Piles	PM	2.1	9.4
F-04	Inactive Coal Pile	PM	2.3	10.1
F-05	Dozing of Solid Waste Disposal Area	PM	10.7	46.9

SN	Description	Pollutant	lb/hr	tpy
F-06	Solid Waste Disposal Area	PM	4.4	19.0

66. The permittee shall treat the Active Piles, SN-F-01 and SN-F-02, with water each day that precipitation is less than 0.1 inches. Water treatment is also not required when the ambient temperature is below 40 degrees F. The permittee shall also maintain a daily log which shows if water was applied to the Active Piles, and the precipitation amounts or temperature on days it was not applied. The permittee shall treat the freshly disturbed areas of the Inactive Pile, SN-F-04, with water or chemical dust suppressant sprays on a daily basis. These treatments shall not be required if the ambient temperature is below 40 degrees F or if the precipitation is greater that 0.1 inch. The permittee shall maintain a daily log of the water and dust suppressant treatment to the Inactive Pile. On days where no treatment occurs the log shall document either that no new areas were disturbed, the ambient temperature on that day was below 40 degrees F, or that precipitation on that day was greater than 0.1 inch. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

67. The maximum area of the solid waste disposal area, SN-F-06, that is operating/exposed shall not exceed 50 acres. The permittee shall certify that the area does not exceed 50 acres in the semi-annual reports required in General Provision 7. [Regulation 19, §19.705, Regulation 18, §18.1004, 40 CFR 52, Subpart E and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

68. The coal and solid waste piles shall be operated in a manner to prohibit visible emission off site of the facility. Compliance with the opacity standard shall be demonstrated through compliance with Specific Condition 69. [§19.503 of Regulation 19 and 40 CFR Part 52, Subpart E]

69. Weekly visible emission observations shall conducted of the coal and solid waste piles.

    a. If during the observations, any visible emissions are detected off-site, the permittee shall:

        i. Take immediate action to identify the cause of the visible emissions,
        ii. Implement corrective action,
        iii. If excessive visible emissions are still detected further corrective measures shall be taken.
        iv. If no excessive visible emissions are detected, the incident shall be noted in the records as described below.

    b. The permittee shall maintain records related to all visible emission observations. These records shall be updated on an as-performed basis. These records shall be kept on site and made available to Department personnel upon request. These records shall contain:

ix. The time and date of each observation/reading,
x. The results of the observations,
xi. The cause of any observed exceedance of opacity limits, corrective actions taken, results of the reassessment, and
xii. The name of the person conducting the observation/reading.

[Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

SN-CT-01
Cooling Tower

Source Description

Cooling water used in the steam turbine condenser is provided by a mechanical draft cooling tower.

Specific Conditions

70. The permittee shall not exceed the emission rates set forth in the following table. Emission rates are based on the maximum operating capacity of the equipment. Compliance shall be demonstrated through compliance with Plantwide Condition 5. [Regulation 19, §19.901 et seq., effective October 15, 2007 and 40 CFR Part 52, Subpart E, Regulation 19, §19.304 and 40 CFR 63.43]

Pollutant	lb/hr	tpy
PM_{10}	5.2	22.8

71. The permittee shall not exceed the emission rates set forth in the following table. Emission rates are based on the maximum operating capacity of the equipment. Compliance shall be demonstrated through compliance with Plantwide Condition 5. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	5.2	22.8

72. This source shall be equipped with high efficiency drift eliminators with a drift rate not greater than 0.0005%. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

73. The total dissolved solids in the cooling tower recirculated water shall not exceed 7500 ppm. Compliance with this limit shall be demonstrated by Specific Condition 74.

74. The permittee shall monitor the total dissolved solids in the cooling tower once per week. These records shall be updated by the 15th day of the month after the month which the records represent, be kept on site, and be made available to Department personnel upon request. Reports of these records shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 70.6]

SN-RD-01
Roads

Source Description

Truck traffic to and from the landfill and throughout the plant takes place on unpaved roads.

Specific Conditions

75. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Condition 77. [Regulation 19, §19.901 et seq., effective October 15, 2007 and 40 CFR Part 52, Subpart E, Regulation 19, §19.304 and 40 CFR 63.43]

Pollutant	lb/hr	tpy
PM_{10}	1.1	3.3

76. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Condition 77. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	3.8	11.9

77. The permittee shall develop a haul road maintenance plan to clean or treat haul roads at this facility. This plan shall be designed to minimize emissions from this source. A copy of this plan shall be kept on site and made available to Department personnel upon request. At a minimum, the plan shall contain the elements listed in a - c below. [Regulation 18, §18.1004, Regulation 19, §19.705, 40 CFR 70.6 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

a) At a minimum, the frequency of application of water or dust suppressant shall occur daily unless otherwise required as a result of inspections required by b) below.

b) Daily inspections of unpaved roadways shall occur to determine the needed frequencies of application of dust suppressant. If this daily inspection determines that the unpaved roadways are covered with snow and/or ice, or if precipitation has occurred that is sufficient for that day to ensure fugitive dust has been minimized, then the requirements of shall not apply for that day.

c) The facility shall maintain records of these daily inspections including observed conditions and actions taken

SECTION V: COMPLIANCE PLAN AND SCHEDULE

This is the initial permit for the John W. Turk, Jr. Power Plant. The facility will examine and analyze future regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Regulation 19, §19.704, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Regulation 19, §19.410(B) and 40 CFR Part 52, Subpart E]

3. The permittee must test any equipment scheduled for testing, unless stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) days in advance of such test. The permittee shall submit the compliance test results to the Department within thirty (30) days after completing the testing. [Regulation 19, §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

4. The permittee must provide: [Regulation 19, §19.702 and/or Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

    a. Sampling ports adequate for applicable test methods;
    b. Safe sampling platforms;
    c. Safe access to sampling platforms; and
    d. Utilities for sampling and testing equipment.

5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [Regulation 19, §19.303 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

6. This permit subsumes and incorporates all previously issued air permits for this facility. [Regulation 26 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

7. The permittee shall comply with all applicable requirements contained in 40 CFR 63, Subpart A. [Regulation No. 19 §19.304 and 40 CFR 63.43(g)(2)(iv)]

8. The permittee must prepare and implement a Startup, Shutdown, and Malfunction Plan (SSM) for SN-01 and SN-02. If the Department requests a review of the SSM, the

permittee will make the SSM available for review. The permittee must keep a copy of the SSM at the source's location and retain all previous versions of the SSM plan for five years. [Regulation 19, §19.304 and 40 CFR 63.6(e)(3)]

9. The CEMS required by this permit shall be operated in accordance with all applicable conditions of the Department's Continuous Emission Monitoring Systems Conditions as found in Appendix F of this permit. [Regulation 19, §19.703, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Title VI Provisions

10. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 CFR Part 82, Subpart E]

    a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to §82.106.
    b. The placement of the required warning statement must comply with the requirements pursuant to §82.108.
    c. The form of the label bearing the required warning must comply with the requirements pursuant to §82.110.
    d. No person may modify, remove, or interfere with the required warning statement except as described in §82.112.

11. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 CFR Part 82, Subpart F]

    a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.
    b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.
    c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.
    d. Persons disposing of small appliances, MVACs, and MVAC like appliances must comply with record keeping requirements pursuant to §82.166. ("MVAC like appliance" as defined at §82.152)
    e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to §82.156.
    f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

12. If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 CFR Part 82, Subpart A, Production and Consumption Controls.

13. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

    The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC 22 refrigerant.

14. The permittee can switch from any ozone depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR Part 82, Subpart G.

Acid Rain (Title IV)

15. The Director prohibits the permittee to cause any emissions exceeding any allowances the source lawfully holds under Title IV of the Act or the regulations promulgated under the Act. No permit revision is required for increases in emissions allowed by allowances acquired pursuant to the acid rain program, if such increases do not require a permit revision under any other applicable requirement. This permit establishes no limit on the number of allowances held by the permittee. However, the source may not use allowances as a defense for noncompliance with any other applicable requirement of this permit or the Act. The permittee will account for any such allowance according to the procedures established in regulations promulgated under Title IV of the Act. [Regulation 26, §26.701 and 40 CFR 70.6(a)(4)]

Mitigation of Visibility Impacts in Federal Class I Areas

16. Not later than twelve (12) months after the initial commencement [or "startup"] of operation of the main boiler (SN-01) at the Permittee's John W. Turk, Jr. Power Plant, SWEPCO shall obtain a final revision of Permit No. PSD-TX-3 for Unit 2 at the SWEPCO's Welsh Power Plant located in Pittsburg, Titus County, Texas from the Texas Commission on Environmental Quality (TCEQ) containing a federally enforceable emissions limitation of no more than 2,165 pounds of SO_2 per hour on a 24-hour rolling average basis, and a maximum of 9,483 tons per year. Within the same time frame as the first sentence in this paragraph, SWEPCO shall also secure from TCEQ a final action incorporating the emissions limitations described in this paragraph as federally enforceable emission limitations in the Welsh Plant's Federal (Title V) Operating Permit. SWEPCO shall submit a copy of such permits to the Department and the United States

Forest Service within thirty (30) days of issuance of the Welsh Unit 2 permits. Within the same time frame as the first sentence in this paragraph, SWEPCO shall submit emissions data demonstrating that SWEPCO has achieved and maintained compliance with an emission rate of no more than 2,165 pounds of SO_2 per hour on a 24-hour rolling average basis at Welsh Unit 2 for a period of at least thirty (30) days after the effective date for those federally enforceable emission limitations. Lastly, SWEPCO shall submit emissions data demonstrating compliance with an emission rate of no more than 2,165 pounds of SO_2 per hour on a 24-hour rolling average basis at Welsh Unit 2 semi-annually thereafter in accordance with General Provision #7.

17. During the first twelve months of operation of SN-01, or until the conditions of paragraph (1) have been fully satisfied, whichever is earlier, SO_2 emissions from SN-01 shall not exceed 480 pounds per hour on a 24-hour rolling average basis or a total of 1,900 tons per year as measured by the CEMS required by this permit. As stated in paragraph (3) below, if any condition in paragraph (1) is not met on the date specified, then, the emissions from SN-01 shall not exceed the pounds per hour levels in Table 1 on a 24-hour rolling average basis and the tons per year levels in Table 1 on a rolling 12-month basis until such time as the conditions in paragraph (1) are met.

18. Regardless of any provisions of this permit to the contrary, if SWEPCO has not obtained the permits as required by paragraph (1) for Unit 2 at the Welsh Plant from TCEQ; if SWEPCO fails to submit the required documentation to the Department and the United States Forest Service within the time frames specified in paragraph (1) above; or if the submissions of the required documentation demonstrate non-compliance with the emissions limitations stated in paragraph (1) above, emissions from SN-01 thereafter shall not exceed the pounds per hour levels in Table 1 on a 24-hour rolling average basis and the tons per year levels in Table 1 on a rolling 12-month basis until such time as the conditions in paragraph (1) are met.

Table 1:

Pollutant	Tons/Year	Lbs/hr
Sulfur dioxide	908	207
Nitrogen oxides	827	189
Particulate Matter (PM_{10}) Total	402	92

19. Within ninety (90) days after the first twelve months of operation of SN-01, or the effective date of the mitigation required by paragraph 1, whichever is earlier, the SWEPCO shall permanently surrender six (6) Acid Rain Program SO_2 allowances originally allocated to Welsh Unit 2 for each day from the date that SN-01 commences operation to the effective date of the mitigation required in paragraph 1 or the end of the 12-month period. The total Acid Rain Program SO_2 allowances permanently surrendered during the effective period shall not exceed 1,907 allowances. SWEPCO shall submit, in

accordance with the provisions of General Condition 7 of this permit, certification to the Department that Acid Rain Program allowance have been surrendered.

SECTION VII: INSIGNIFICANT ACTIVITIES

The following sources are insignificant activities. Any activity that has a state or federal applicable requirement shall be considered a significant activity even if this activity meets the criteria of §26.304 of Regulation 26 or listed in the table below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated August 11, 2006.

Description	Category
Diesel Storage	Group A, #3

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 CFR 70.6(b)(2)]

2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 CFR 70.6(a)(2) and §26.701(B) of the Regulations of the Arkansas Operating Air Permit Program (Regulation 26), effective September 26, 2002]

3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due. [Regulation 26, §26.406]

4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, et seq. (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 CFR 70.6(a)(1)(ii) and Regulation 26, §26.701(A)(2)]

5. The permittee must maintain the following records of monitoring information as required by this permit. [40 CFR 70.6(a)(3)(ii)(A) and Regulation 26, §26.701(C)(2)]

    a. The date, place as defined in this permit, and time of sampling or measurements;
    b. The date(s) analyses performed;
    c. The company or entity performing the analyses;
    d. The analytical techniques or methods used;
    e. The results of such analyses; and
    f. The operating conditions existing at the time of sampling or measurement.

6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample,

measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 CFR 70.6(a)(3)(ii)(B) and Regulation 26, §26.701(C)(2)(b)]

7. The permittee must submit reports of all required monitoring every six (6) months. If permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due within thirty (30) days of the end of the reporting period. Although the reports are due every six months, each report shall contain a full year of data. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Regulation No. 26, §26.2 must certify all required reports. The permittee will send the reports to the address below: [40 C.F.R. 70.6(a)(3)(iii)(A) and Regulation 26, §26.701(C)(3)(a)]

   Arkansas Department of Environmental Quality
   Air Division
   ATTN: Compliance Inspector Supervisor
   Post Office Box 8913
   Little Rock, AR 72219

8. The permittee shall report to the Department all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.

   a. For all upset conditions (as defined in Regulation19, § 19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:

      i. The facility name and location
      ii. The process unit or emission source deviating from the permit limit,
      iii. The permit limit, including the identification of pollutants, from which deviation occurs,
      iv. The date and time the deviation started,
      v. The duration of the deviation,
      vi. The average emissions during the deviation,
      vii. The probable cause of such deviations,
      viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future, and
      ix. The name of the person submitting the report.

   The permittee shall make a full report in writing to the Department within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.

[Regulation 19, §19.601 and §19.602, Regulation 26, §26.701(C) (3) (b), and 40 CFR 70.6(a) (3) (iii) (B)]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 CFR 70.6(a)(5), Regulation 26, §26.701(E), and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. §7401, et seq. and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 CFR 70.6(a)(6)(i) and Regulation 26, §26.701(F)(1)]

11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 CFR 70.6(a)(6)(ii) and Regulation 26, §26.701(F)(2)]

12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR 70.6(a)(6)(iii) and Regulation 26, §26.701(F)(3)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR 70.6(a)(6)(iv) and Regulation 26, §26.701(F)(4)]

14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Department may require the permittee to furnish such records directly to the Director

along with a claim of confidentiality. [40 CFR 70.6(a)(6)(v) and Regulation 26, §26.701(F)(5)]

15. The permittee must pay all permit fees in accordance with the procedures established in Regulation 9. [40 CFR 70.6(a)(7) and Regulation 26, §26.701(G)]

16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 CFR 70.6(a)(8) and Regulation 26, §26.701(H)]

17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 CFR 70.6(a)(9)(i) and Regulation 26, §26.701(I)(1)]

18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 CFR 70.6(b) and Regulation 26, §26.702(A) and (B)]

19. Any document (including reports) required by this permit must contain a certification by a responsible official as defined in Regulation 26, §26.2. [40 CFR 70.6(c)(1) and Regulation 26, §26.703(A)]

20. The permittee must allow an authorized representative of the Department, upon presentation of credentials, to perform the following: [40 CFR 70.6(c)(2) and Regulation 26, §26.703(B)]

    a. Enter upon the permittee's premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
    b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;
    c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
    d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually within 30 days following the last day of the anniversary month of the initial Title V permit. The permittee must also

submit the compliance certification to the Administrator as well as to the Department. All compliance certifications required by this permit must include the following: [40 CFR 70.6(c)(5) and Regulation 26, §26.703(E)(3)]

a. The identification of each term or condition of the permit that is the basis of the certification;
b. The compliance status;
c. Whether compliance was continuous or intermittent;
d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit;
e. and Such other facts as the Department may require elsewhere in this permit or by §114(a)(3) and §504(b) of the Act.

22. Nothing in this permit will alter or affect the following: [Regulation 26, §26.704(C)]

a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
c. The applicable requirements of the acid rain program, consistent with §408(a) of the Act or,
d. The ability of EPA to obtain information from a source pursuant to §114 of the Act.

23. This permit authorizes only those pollutant emitting activities addressed in this permit. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Appendix A

40 CFR Part 60, Subpart Da – *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978*

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

Source: 72 FR 32722, June 13, 2007, unless otherwise noted.

§ 60.40Da Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction, modification, or reconstruction is commenced after September 18, 1978.

(b) Combined cycle gas turbines (both the stationary combustion turbine and any associated duct burners) are subject to this part and not subject to subpart GG or KKKK of this part if:

(1) The combined cycle gas turbine is capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) The combined cycle gas turbine is designed and intended to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas on a 12-month rolling average basis; and

(3) The combined cycle gas turbine commenced construction, modification, or reconstruction after February 28, 2005.

(4) This subpart will continue to apply to all other electric utility combined cycle gas turbines that are capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel in the heat recovery steam generator. If the heat recovery steam generator is subject to this subpart and the stationary combustion turbine is subject to either subpart GG or KKKK of this part, only emissions resulting from combustion of fuels in the steam-generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

§ 60.41Da Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

Anthracite means coal that is classified as anthracite according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Available purchase power means the lesser of the following:

(a) The sum of available system capacity in all neighboring companies.

(b) The sum of the rated capacities of the power interconnection devices between the principal company and all neighboring companies, minus the sum of the electric power load on these interconnections.

(c) The rated capacity of the power transmission lines between the power interconnection devices and the electric generating units (the unit in the principal company that has the malfunctioning flue gas desulfurization system and the unit(s) in the neighboring company supplying replacement electrical power) less the electric power load on these transmission lines.

Available system capacity means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

Biomass means plant materials and animal waste.

Bituminous coal means coal that is classified as bituminous according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Boiler operating day for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, *boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17) and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other fuels in any amount.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Cogeneration, also known as "combined heat and power," means a steam-generating unit that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Combined cycle gas turbine means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

Dry flue gas desulfurization technology or *dry FGD* means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides (SO_2) from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry FGD technology include, but are not limited to, lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Electric utility combined cycle gas turbine means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

Electric utility company means the largest interconnected organization, business, or governmental entity that generates electric power for sale (*e.g.* , a holding company with operating subsidiary companies).

Electric utility steam-generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

Electrostatic precipitator or *ESP* means an add-on air pollution control device used to capture particulate matter (PM) by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

Emergency condition means that period of time when:

(1) The electric generation output of an affected facility with a malfunctioning flue gas desulfurization system cannot be reduced or electrical output must be increased because:

(i) All available system capacity in the principal company interconnected with the affected facility is being operated, and

(ii) All available purchase power interconnected with the affected facility is being obtained, or

(2) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

(3) An affected facility with a malfunctioning flue gas desulfurization system becomes the only available unit to maintain a part or all of the principal company's system emergency reserves and the unit is operated in spinning reserve at the lowest practical electric generation load consistent with not causing significant physical damage to the unit. If the unit is operated at a higher load to meet load demand, an emergency condition would not exist unless the conditions under paragraph (1) of this definition apply.

Emission limitation means any emissions limit or operating limit.

Emission rate period means any calendar month included in a 12-month rolling average period.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the fuel burned in stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

24-hour period means the period of time between 12:01 a.m. and 12:00 midnight.

Integrated gasification combined cycle electric utility steam generating unit or *IGCC electric utility steam generating unit* means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No coal is directly burned in the unit during operation.

Interconnected means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means coal that is classified as lignite A or B according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per standard cubic meter (910 and 1,150 Btu per standard cubic foot).

Neighboring company means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Net system capacity means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Petroleum means crude oil or petroleum or a fuel derived from crude oil or petroleum, including, but not limited to, distillate oil, residual oil, and petroleum coke.

Potential combustion concentration means the theoretical emissions (nanograms per joule (ng/J), lb/MMBtu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems) and:

(1) For particulate matter (PM) is:

(i) 3,000 ng/J (7.0 lb/MMBtu) heat input for solid fuel; and

(ii) 73 ng/J (0.17 lb/MMBtu) heat input for liquid fuels.

(2) For sulfur dioxide (SO_2) is determined under §60.50Da(c).

(3) For nitrogen oxides (NO_X) is:

(i) 290 ng/J (0.67 lb/MMBtu) heat input for gaseous fuels;

(ii) 310 ng/J (0.72 lb/MMBtu) heat input for liquid fuels; and

(iii) 990 ng/J (2.30 lb/MMBtu) heat input for solid fuels.

Potential electrical output capacity means 33 percent of the maximum design heat input capacity of the steam generating unit, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr (*e.g.* , a steam generating unit with a 100 MW (340 MMBtu/hr) fossil-fuel heat input capacity would have a 289,080 MWh 12 month potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

Principal company means the electric utility company or companies which own the affected facility.

Resource recovery unit means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

Responsible official means responsible official as defined in 40 CFR 70.2.

Solid-derived fuel means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, synthetic gas, gasified coal, gasified petroleum coke, gasified biomass, and gasified tire derived fuel.

Spare flue gas desulfurization system module means a separate system of SO_2emission control equipment capable of treating an amount of flue gas equal to the total amount of flue gas generated by an affected facility when operated at maximum capacity divided by the total number of nonspare flue gas desulfurization modules in the system.

Spinning reserve means the sum of the unutilized net generating capability of all units of the electric utility company that are synchronized to the power distribution system and that are capable of immediately accepting additional load. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

System emergency reserves means an amount of electric generating capacity equivalent to the rated capacity of the single largest electric generating unit in the electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) which is interconnected with the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

System load means the entire electric demand of an electric utility company's service area interconnected with the affected facility that has the malfunctioning flue gas desulfurization system plus firm contractual sales to other electric utility companies. Sales to other electric utility companies (*e.g.* , emergency power) not on a firm contractual basis may also be included in the system load when no available system capacity exists in the electric utility company to which the power is supplied for sale.

Wet flue gas desulfurization technology or *wet FGD* means a SO_2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet FGD technology include, but are not limited to, lime, limestone, and sodium.

§ 60.42Da Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain PM in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the initial PM performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(c) Except as provided in paragraph (d) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain PM in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) 0.1 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.9 percent reduction) for an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel, or

(3) 0.2 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel.

§ 60.43Da Standard for sulfur dioxide (SO2).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain SO_2in excess of:

(1) 520 ng/J (1.20 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction); or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain SO_2in excess of:

(1) 340 ng/J (0.80 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction); or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC–I) any gases that contain SO_2in excess of 520 ng/J (1.20 lb/MMBtu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/MMBtu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite;

(2) Is classified as a resource recovery unit; or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dioxide emissions are limited to 340 ng/J (0.80 lb/MMBtu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO_2commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of $SO_2$to the atmosphere are greater than 260 ng/J (0.60 lb/MMBtu) heat input

$$E_s = \frac{(340x + 520y)}{100} \quad \text{and} \quad \%P_s = 10$$

(2) If emissions of $SO_2$to the atmosphere are equal to or less than 260 ng/J (0.60 lb/MMBtu) heat input:

$$E_s = \frac{(340x + 520y)}{100} \quad \text{and} \quad \%P_s = \frac{(10x + 30y)}{100}$$

Where:

E_s= Prorated SO_2emission limit (ng/J heat input);

$\%P_s$= Percentage of potential SO_2emission allowed;

x = Percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels); and

y = Percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels).

(i) Except as provided in paragraphs (j) and (k) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(j) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, shall caused to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain SO_2in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(k) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area that commenced construction, reconstruction, or modification commenced after February 28, 2005, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of the applicable emission limitation specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input on a 30-day rolling average basis.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2in excess of if the affected facility or 230 ng/J (0.54 lb/MMBtu) heat input on a 30-day rolling average basis.

§ 60.44Da Standard for nitrogen oxides (NOX).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraphs (b), (d), (e), and (f) of this section, any gases that contain NO_X(expressed as NO_2) in excess of the following emission limits, based on a 30-day rolling average basis, except as provided under §60.48Da(j)(1):

(1) NO_Xemission limits.

Fuel type	Emission limit for heat input	
	ng/J	lb/MMBtu
Gaseous fuels:		
Coal-derived fuels	210	0.50
All other fuels	86	0.20
Liquid fuels:		
Coal-derived fuels	210	0.50
Shale oil	210	0.50
All other fuels	130	0.30
Solid fuels:		
Coal-derived fuels	210	0.50
Any fuel containing more than 25%, by weight, coal refuse	(1)	(1)
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace[2]	340	0.80
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit[2]	260	0.60
Subbituminous coal	210	0.50
Bituminous coal	260	0.60
Anthracite coal	260	0.60
All other fuels	260	0.60

[1]Exempt from NO_Xstandards and NO_Xmonitoring requirements.

[2]Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

(2) NO_Xreduction requirement.

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels	25
Liquid fuels	30
Solid fuels	65

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(c) Except as provided under paragraphs (d), (e), and (f) of this section, when two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$$E_n = \frac{(86w + 130x + 210y + 260z + 340v)}{100}$$

Where:

E_n= Applicable standard for $NO_X$when multiple fuels are combusted simultaneously (ng/J heat input);

w = Percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x = Percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y = Percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;

z = Percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v = Percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(d)(1) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction after July 9, 1997, but before or on February 28, 2005 shall cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 200 ng/J (1.6 lb/MWh) gross energy output, based on a 30-day rolling average basis, except as provided under §60.48Da(k).

(2) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of affected facility for which reconstruction commenced after July 9, 1997, but before or on February 28, 2005 shall cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 65 ng/J (0.15 lb/MMBtu) heat input, based on a 30-day rolling average basis.

(e) Except for an IGCC electric utility steam generating unit meeting the requirements of paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X(expressed as NO_2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under §60.48Da(k).

(2) For an affected facility for which reconstruction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis.

(f) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an IGCC electric utility steam generating unit subject to the provisions of this subpart and for which construction, reconstruction, or modification commenced after February 28, 2005, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) Except as provided for in paragraphs (f)(2) and (3) of this section, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis.

(2) When burning liquid fuel exclusively or in combination with solid-derived fuel such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of 190 ng/J (1.5 lb/MWh) gross energy output on a 30-day rolling average basis.

(3) In cases when during a 30-day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the clock hours in the 30-day period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X(expressed as NO_2) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

§ 60.45Da Standard for mercury (Hg).

(a) For each coal-fired electric utility steam generating unit other than an IGCC electric utility steam generating unit, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases that contain mercury (Hg) emissions in excess of each Hg emissions limit in paragraphs (a)(1) through (5) of this section that applies to you. The Hg emissions limits in paragraphs (a)(1) through (5) of this section are based on a 12-month rolling average basis using the procedures in §60.50Da(h).

(1) For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 20×10^{-6} pound per megawatt hour (lb/MWh) or 0.020 lb/gigawatt-hour (GWh) on an output basis. The International System of Units (SI) equivalent is 0.0025 ng/J.

(2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal:

(i) If your unit is located in a county-level geographical area receiving greater than 25 inches per year (in/yr) mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 66×10^{-6} lb/MWh or 0.066 lb/GWh on an output basis. The SI equivalent is 0.0083 ng/J.

(ii) If your unit is located in a county-level geographical area receiving less than or equal to 25 in/yr mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 97×10^{-6} lb/MWh or 0.097 lb/GWh on an output basis. The SI equivalent is 0.0122 ng/J.

(3) For each coal-fired electric utility steam generating unit that burns only lignite, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 175×10^{-6} lb/MWh or 0.175 lb/GWh on an output basis. The SI equivalent is 0.0221 ng/J.

(4) For each coal-burning electric utility steam generating unit that burns only coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of 16×10^{-6} lb/MWh or 0.016 lb/GWh on an output basis. The SI equivalent is 0.0020 ng/J.

(5) For each coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks (*i.e.* , bituminous coal, subbituminous coal, lignite) or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the unit-specific Hg emissions limit established according to paragraph (a)(5)(i) or (ii) of this section, as applicable to the affected unit.

(i) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emissions limit based on the Btu, MWh, or MJ) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 in this section. For each affected source, you must comply with the weighted Hg emissions limit calculated using Equation 1 in this section based on the total Hg emissions from the unit and the total Btu, MWh, or MJ contributed by all fuels burned during the compliance period.

$$EL_b = \frac{\sum_{i=1}^{n} EL_i (HH_i)}{\sum_{i=1}^{n} HH_i} \qquad \text{(Eq. 1)}$$

Where:

EL_b= Total allowable Hg in lb/MWh that can be emitted to the atmosphere from any affected source being averaged according to this paragraph.

EL_i= Hg emissions limit for the subcategory i (coal rank) that applies to affected source, lb/MWh;

HH_i= For each affected source, the Btu, MWh, or MJ contributed by the corresponding subcategory i (coal rank) burned during the compliance period; and

n = Number of subcategories (coal ranks) being averaged for an affected source.

(ii) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse together with one or more non-regulated, supplementary fuels, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emission limit based on the Btu, MWh, or MJ contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 in this section. For each affected source. You must comply with the weighted Hg emissions limit calculated using Equation 1 in this section based on the total Hg emissions from the unit contributed by both regulated and nonregulated fuels burned during the compliance period and the total Btu, MWh, or MJ contributed by both regulated and nonregulated fuels burned during the compliance period.

(b) For each IGCC electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases that contain Hg emissions in excess of 20×10^{-6} lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J. This Hg emissions limit is based on a 12-month rolling average basis using the procedures in §60.50Da(h).

§ 60.46Da [Reserved]

§ 60.47Da Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC–I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2emission reduction requirements under §60.43Da(c) but must, as a minimum, reduce SO_2emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2emission reduction requirements under §60.43Da(a) but must, as a minimum, reduce SO_2emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable NO_Xemission limitation and percent reduction under §60.44Da(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/MMBtu) heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Solid solvent refined coal (SCR I)	SO2	6,000–10,000
Fluidized bed combustion (atmospheric)	SO2	400–3,000
Fluidized bed combustion (pressurized)	SO2	400–1,200
Coal liquification	NOX	750–10,000
Total allowable for all technologies		15,000

§ 60.48Da Compliance provisions.

(a) Compliance with the PM emission limitation under §60.42Da(a)(1) constitutes compliance with the percent reduction requirements for PM under §60.42Da(a)(2) and (3).

(b) Compliance with the NO_Xemission limitation under §60.44Da(a)(1) constitutes compliance with the percent reduction requirements under §60.44Da(a)(2).

(c) The PM emission standards under §60.42Da, the NO_X emission standards under §60.44Da, and the Hg emission standards under §60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

(d) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if SO_2 emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,

(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any SO_2 emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 MMBtu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph under §60.43Da(a), (b), (d), (e), and (h) for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,

(ii) The affected facility is operating at the maximum heat input rate,

(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

(e) After the initial performance test required under §60.8, compliance with the SO_2 emission limitations and percentage reduction requirements under §60.43Da and the NO_X emission limitations under §60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both SO_2 and NO_X and a new percent reduction for SO_2 are calculated to show compliance with the standards.

(f) For the initial performance test required under §60.8, compliance with the SO_2 emission limitations and percent reduction requirements under §60.43Da and the NO_X emission limitation under §60.44Da is based on the average emission rates for SO_2, NO_X, and percent reduction for SO_2 for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

(1) Compliance with applicable 30-day rolling average SO_2 and NO_X emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_X for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_X only), or emergency conditions (SO_2 only).

(2) Compliance with applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days.

(3) Compliance with applicable daily average PM emission limitations is determined by calculating the arithmetic average of all hourly emission rates for PM each boiler operating day, except for data obtained during startup, shutdown, and malfunction. Averages are only calculated for boiler operating days that have valid data for at least 18 hours of unit operation during which the standard applies. Instead, the valid hourly emission rates are averaged with the next boiler operating day with 18 hours or more of valid PM CEMS data to determine compliance.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under §60.49Da of this subpart, compliance of the affected facility with the emission requirements under §§60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19 of appendix A of this part.

(i) *Compliance provisions for sources subject to §60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), or (f)* . The owner or operator of an affected facility subject to §60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), or (f) shall calculate NO_Xemissions as 1.194×10^{-7} lb/scf-ppm times the average hourly NO_Xoutput concentration in ppm (measured according to the provisions of §60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)). Alternatively, for oil-fired and gas-fired units, NO_Xemissions may be calculated by multiplying the hourly NO_Xemission rate in lb/MMBtu (measured by the CEMS required under §§60.49Da(c) and (d)), by the hourly heat input rate (measured according to the provisions of §60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of §60.49Da(k)).

(j) *Compliance provisions for duct burners subject to §60.44Da(a)(1)* . To determine compliance with the emissions limits for NO_Xrequired by §60.44Da(a) for duct burners used in combined cycle systems, either of the procedures described in paragraph (j)(1) or (2) of this section may be used:

(1) The owner or operator of an affected duct burner shall conduct the performance test required under §60.8 using the appropriate methods in appendix A of this part. Compliance with the emissions limits under §60.44Da(a)(1) is determined on the average of three (nominal 1-hour) runs for the initial and subsequent performance tests. During the performance test, one sampling site shall be located in the exhaust of the turbine prior to the duct burner. A second sampling site shall be located at the outlet from the heat recovery steam generating unit. Measurements shall be taken at both sampling sites during the performance test; or

(2) The owner or operator of an affected duct burner may elect to determine compliance by using the continuous emission monitoring system (CEMS) specified under §60.49Da for measuring $NO_X$and oxygen (O_2) (or carbon dioxide (CO_2)) and meet the requirements of §60.49Da. Alternatively, data from a NO_Xemission rate (*i.e.* , NO_X-diluent) CEMS certified according to the provisions of §75.20(c) of this chapter and appendix A to part 75 of this chapter, and meeting the quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, may be used, with the following caveats. Data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter. The sampling site shall be located at the outlet from the steam generating unit. The NO_Xemission rate at the outlet from the steam generating unit shall constitute the NO_Xemission rate from the duct burner of the combined cycle system.

(k) *Compliance provisions for duct burners subject to §60.44Da(d)(1) or (e)(1)* . To determine compliance with the emission limitation for NO_Xrequired by §60.44Da(d)(1) or (e)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:

(1) The owner or operator of an affected duct burner used in combined cycle systems shall determine compliance with the applicable NO_Xemission limitation in §60.44Da(d)(1) or (e)(1) as follows:

(i) The emission rate (E) of NO_Xshall be computed using Equation 2 in this section:

$$E = \frac{(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})}{(O_{sg} \times h)} \qquad \text{(Eq. 2)}$$

Where:

E = Emission rate of $NO_X$from the duct burner, ng/J (lb/MWh) gross output;

C_{sg}= Average hourly concentration of NO_Xexiting the steam generating unit, ng/dscm (lb/dscf);

C_{te}= Average hourly concentration of NO_Xin the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf);

Q_{sg}= Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr);

Q_{te}= Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr);

O_{sg}= Average hourly gross energy output from steam generating unit, J (MWh); and

h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(ii) Method 7E of appendix A of this part shall be used to determine the NO_Xconcentrations ($C_{sg}$and C_{te}). Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates ($Q_{sg}$and Q_{te}) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(iii) The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(iv) Compliance with the applicable NO_Xemission limitation in §60.44Da(d)(1) or (e)(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests.

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the applicable NO_Xemission limitation in §60.44Da(d)(1) or (e)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

(i) The emission rate (E) of NO_Xshall be computed using Equation 3 in this section:

$$E = \frac{\left(C_{sg} \times Q_{sd}\right)}{O_{cc}} \qquad (Eq. 3)$$

Where:

E = Emission rate of $NO_X$from the duct burner, ng/J (lb/MWh) gross output;

C_{sg}= Average hourly concentration of NO_Xexiting the steam generating unit, ng/dscm (lb/dscf);

Q_{sg}= Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr); and

O_{cc}= Average hourly gross energy output from entire combined cycle unit, J (MWh).

(ii) The CEMS specified under §60.49Da for measuring $NO_X$and O_2(or CO_2) shall be used to determine the average hourly NO_Xconcentrations (C_{sg}). The continuous flow monitoring system specified in §60.49Da(l) or §60.49Da(m) shall be used to determine the volumetric flow rate (Q_{sg}) of the exhaust gas. If the option to use the flow monitoring system in §60.49Da(m) is selected, the flow rate data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter. The sampling site shall be located at the outlet from the steam generating unit.

(iii) The continuous monitoring system specified under §60.49Da(k) for measuring and determining gross energy output shall be used to determine the average hourly gross energy output from the entire combined cycle unit (O_{cc}), which is the combined output from the combustion turbine and the steam generating unit.

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in §60.49Da(l), determine the mass rate (lb/hr) of NO_Xemissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of part 75 of this chapter. If this compliance option is selected, the emission rate (E) of NO_Xshall be computed using Equation 4 in this section:

$$E = \frac{(ER_{sg} \times H_{cc})}{O_{cc}} \quad \text{(Eq. 4)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross output;

ER_{sg}= Average hourly emission rate of NO_X exiting the steam generating unit heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part, ng/J (lb/MMBtu);

H_{cc}= Average hourly heat input rate of entire combined cycle unit, J/hr (MMBtu/hr); and

O_{cc}= Average hourly gross energy output from entire combined cycle unit, J (MWh).

(3) When an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

(i) Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common steam turbine; or

(ii) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(l) *Compliance provisions for sources subject to §60.45Da.* The owner or operator of an affected facility subject to §60.45Da (new sources constructed or reconstructed after January 30, 2004) shall calculate the Hg emission rate (lb/MWh) for each calendar month of the year, using hourly Hg concentrations measured according to the provisions of §60.49Da(p) in conjunction with hourly stack gas volumetric flow rates measured according to the provisions of §60.49Da(l) or (m), and hourly gross electrical outputs, determined according to the provisions in §60.49Da(k). Compliance with the applicable standard under §60.45Da is determined on a 12-month rolling average basis.

(m) *Compliance provisions for sources subject to §60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), or (j)(3)(i).* The owner or operator of an affected facility subject to §60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), or (j)(3)(i) shall calculate SO_2 emissions as 1.660×10^{-7} lb/scf-ppm times the average hourly SO_2 output concentration in ppm (measured according to the provisions of §60.49Da(b)), times the average hourly flow rate (measured according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)). Alternatively, for oil-fired and gas-fired units, SO_2 emissions may be calculated by multiplying the hourly SO_2 emission rate (in lb/MMBtu), measured by the CEMS required under §60.49Da, by the hourly heat input rate (measured according to the provisions of §60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of §60.49Da(k)).

(n) *Compliance provisions for sources subject to §60.42Da(c)(1).* The owner or operator of an affected facility subject to §60.42Da(c)(1) shall calculate PM emissions by multiplying the average hourly PM output concentration, measured according to the provisions of §60.49Da(t), by the average hourly flow rate, measured according to the provisions of §60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of §60.49Da(k). Compliance with the emission limit is determined by calculating the arithmetic average of the hourly emission rates computed for each boiler operating day.

(o) *Compliance provisions for sources subject to §60.42Da(c)(2) or (d).* Except as provided for in paragraph (p) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, shall demonstrate compliance with each applicable emission limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section and use a COMS to demonstrate compliance with §60.42Da(b).

(1) You must conduct a performance test to demonstrate initial compliance with the applicable PM emissions limit in 60.42Da(c)(2) or (d) by the applicable date specified in §60.8(a). Thereafter, you must conduct each subsequent performance test within 12 calendar months of the date of the prior performance test. You must conduct each performance test according to the requirements in §60.8 using the test methods and procedures in §60.50Da.

(2) You must monitor the performance of each electrostatic precipitator or fabric filter (baghouse) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) using a continuous opacity monitoring system (COMS) according to the requirements in paragraphs (o)(2)(i) through (vi) unless you elect to comply with one of the alternatives provided in paragraphs (o)(3) and (o)(4) of this section, as applicable to your control device.

(i) Each COMS must meet Performance Specification 1 in 40 CFR part 60, appendix B.

(ii) You must comply with the quality assurance requirements in paragraphs (o)(4)(ii)(A) through (E) of this section.

(A) You must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of Performance Specification 1 in 40 CFR part 60, appendix B.

(B) You must adjust the zero and span whenever the 24-hour zero drift or 24-hour span drift exceeds 4 percent opacity. The COMS must allow for the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified. The optical surfaces exposed to the effluent gases must be cleaned prior to performing the zero and span drift adjustments, except for systems using automatic zero adjustments. For systems using automatic zero adjustments, the optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(C) You must apply a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. All procedures applied must provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.

(D) Except during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS must be in continuous operation and must complete a minimum of one cycle of sampling and analyzing for each successive 10 second period and one cycle of data recording for each successive 6-minute period.

(E) You must reduce all data from the COMS to 6-minute averages. Six-minute opacity averages must be calculated from 36 or more data points equally spaced over each 6-minute period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments must not be included in the data averages. An arithmetic or integrated average of all data may be used.

(iii) During each performance test conducted according to paragraph (o)(1) of this section, you must establish an opacity baseline level. The value of the opacity baseline level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurements recorded during each of the test run intervals conducted for the performance test, and then adding 2.5 percent opacity to your calculated average opacity value for all of the test runs. If your calculated average opacity value for all of the test runs is less than 5.0 percent, then the opacity baseline level is set at 5.0 percent.

(iv) You must evaluate the preceding 24-hour average opacity level measured by the COMS each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the measured 24-hour average opacity emission level is greater than the baseline opacity level determined in paragraph (o)(2)(iii) of this section, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high opacity incident and take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the measured 24-hour average opacity to a level below the baseline opacity level.

(v) You must record the opacity measurements, calculations performed, and any corrective actions taken. The record of corrective action taken must include the date and time during which the measured 24-hour average opacity was greater than baseline opacity level, and the date, time, and description of the corrective action.

(vi) If the measured 24-hour average opacity for your affected source remains at a level greater than the opacity baseline level after 7 days, then you must conduct a new PM performance test according to paragraph (o)(1) of this section and establish a new opacity baseline value according to paragraph (o)(2) of this section. This new performance test must be conducted within 60 days of the date that the measured 24-hour average opacity was first determined to exceed the baseline opacity level unless a wavier is granted by the appropriate delegated permitting authority.

(3) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of an electrostatic precipitator (ESP) operated to comply with the applicable PM

emissions limit in §60.42Da(c)(2) or (d) using an ESP predictive model developed in accordance with the requirements in paragraphs (o)(3)(i) through (v) of this section.

(i) You must calibrate the ESP predictive model with each PM control device used to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) operating under normal conditions. In cases when a wet scrubber is used in combination with an ESP to comply with the PM emissions limit, the daily average liquid-to-gas flow rate for the wet scrubber must be maintained at 90 percent of average ratio measured during all test run intervals for the performance test conducted according to paragraph (o)(1) of this section.

(ii) You must develop a site-specific monitoring plan that includes a description of the ESP predictive model used, the model input parameters, and the procedures and criteria for establishing monitoring parameter baseline levels indicative of compliance with the PM emissions limit. You must submit the site-specific monitoring plan for approval by the appropriate delegated permitting authority. For reference purposes in preparing the monitoring plan, see the OAQPS "Compliance Assurance Monitoring (CAM) Protocol for an Electrostatic Precipitator (ESP) Controlling Particulate Matter (PM) Emissions from a Coal-Fired Boiler." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality Planning and Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Continuous Emission Monitoring .

(iii) You must run the ESP predictive model using the applicable input data each boiler operating day and evaluate the model output for the preceding boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the values for one or more of the model parameters exceed the applicable baseline levels determined according to your approved site-specific monitoring plan, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of a model parameter deviation and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to return the model output to within the applicable baseline levels.

(iv) You must record the ESP predictive model inputs and outputs and any corrective actions taken. The record of corrective action taken must include the date and time during which the model output values exceeded the applicable baseline levels, and the date, time, and description of the corrective action.

(v) If after 7 consecutive days a model parameter continues to exceed the applicable baseline level, then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 days of the date that the model parameter was first determined to exceed its baseline level unless a wavier is granted by the appropriate delegated permitting authority.

(4) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of a fabric filter (baghouse) operated to comply with the applicable PM emissions limit in §60.42Da(c)(2) or (d) by using a bag leak detection system according to the requirements in paragraphs (o)(4)(i) through (v) of this section.

(i) Each bag leak detection system must meet the specifications and requirements in paragraphs (o)(4)(i)(A) through (H) of this section.

(A) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per actual cubic meter (0.00044 grains per actual cubic foot) or less.

(B) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator must continuously record the output from the bag leak detection system using electronic or other means (*e.g.* , using a strip chart recorder or a data logger.)

(C) The bag leak detection system must be equipped with an alarm system that will react when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (o)(4)(i)(D) of this section, and the alarm must be located such that it can be noticed by the appropriate plant personnel.

(D) In the initial adjustment of the bag leak detection system, you must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(E) Following initial adjustment, you must not adjust the averaging period, alarm set point, or alarm delay time without approval from the appropriate delegated permitting authority except as provided in paragraph (d)(1)(vi) of this section.

(F) Once per quarter, you may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (o)(4)(ii) of this section.

(G) You must install the bag leak detection sensor downstream of the fabric filter and upstream of any wet scrubber.

(H) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(ii) You must develop and submit to the appropriate delegated permitting authority for approval a site-specific monitoring plan for each bag leak detection system. You must operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (o)(4)(ii)(A) through (F) of this section.

(A) Installation of the bag leak detection system;

(B) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(C) Operation of the bag leak detection system, including quality assurance procedures;

(D) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(E) How the bag leak detection system output will be recorded and stored; and

(F) Corrective action procedures as specified in paragraph (o)(4)(iii) of this section. In approving the site-specific monitoring plan, the appropriate delegated permitting authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.

(iii) For each bag leak detection system, you must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (o)(4)(ii)(F) of this section, you must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:

(A) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(B) Sealing off defective bags or filter media;

(C) Replacing defective bags or filter media or otherwise repairing the control device;

(D) Sealing off a defective fabric filter compartment;

(E) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(F) Shutting down the process producing the particulate emissions.

(iv) You must maintain records of the information specified in paragraphs (o)(4)(iv)(A) through (C) of this section for each bag leak detection system.

(A) Records of the bag leak detection system output;

(B) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(C) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, if procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and if the alarm was alleviated within 3 hours of the alarm.

(v) If after any period of composed of 30 boiler operating days during which the alarm rate exceeds 5 percent of the process operating time (excluding control device or process startup, shutdown, and malfunction), then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 days of the date that the alarm rate was first determined to exceed 5 percent limit unless a wavier is granted by the appropriate delegated permitting authority.

(5) An owner or operator of a modified affected source electing to meet the emission limitations in §.42Da(d) shall determine the percent reduction in PM by using the emission rate for PM determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner or operator may elect to install, certify, maintain, and operate a CEMS measuring PM emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a CEMS measuring PM. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in §60.49Da(v).

(3) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph (p)(1) of this section, whichever is later.

(4) Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19 of appendix A of this part, section 4.1.

(5) At a minimum, valid CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30-day rolling average basis. Beginning on January 1, 2012, valid CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-day rolling average basis.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(6) The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/hr, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(7) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(5) of this section are not met.

(8) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 90 percent (only 75 percent is required prior to January 1, 2012) of all operating hours per 30-day rolling average.

§ 60.49Da Emission monitoring.

(a) Except as provided for in paragraphs (t) and (u) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO_2control system), alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the SO_2control device.

(2) For a facility that qualifies under the numerical limit provisions of §60.43Da(d), (i), (j), or (k) SO_2emissions are only monitored as discharged to the atmosphere.

(3) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of appendix A of this part may be used to determine potential SO_2emissions in place of a continuous SO_2emission monitor at the inlet to the SO_2control device as required under paragraph (b)(1) of this section.

(4) If the owner or operator has installed and certified a SO_2continuous emissions monitoring system (CEMS) according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used to meet the requirements of this section, provided that:

(i) A CO_2or O_2continuous monitoring system is installed, calibrated, maintained and operated at the same location, according to paragraph (d) of this section; and

(ii) For sources subject to an SO_2emission limit in lb/MMBtu under §60.43Da:

(A) When relative accuracy testing is conducted, SO_2concentration data and CO_2(or O_2) data are collected simultaneously; and

(B) In addition to meeting the applicable $SO_2$and CO_2(or O_2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(iii) The reporting requirements of §60.51Da are met. The $SO_2$and CO_2(or O_2) data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2data have been bias adjusted according to the procedures of part 75 of this chapter.

(c)(1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NO_Xemissions discharged to the atmosphere; or

(2) If the owner or operator has installed a NO_Xemission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.51Da. Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2or carbon dioxide (CO_2) content of the flue gases at each location where SO_2or NO_Xemissions are monitored. For affected facilities subject to a lb/MMBtu SO_2emission limit under §60.43Da, if the owner or operator has installed and certified a CO_2or O_2monitoring system according to §75.20(c) of this chapter and appendix A to part 75 of this chapter and the monitoring system continues to meet the applicable quality-assurance provisions of §75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used together with the part 75 SO_2concentration monitoring system described in paragraph (b) of this section, to determine the SO_2emission rate in lb/MMBtu. SO_2data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(e) The CEMS under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

(f)(1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with CEMS, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a CEMS, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph §60.13(h) are expressed in ng/J (lb/MMBtu) heat input and used to calculate the average emission rates under §60.48Da. The 1-hour averages are calculated using the data points required under §60.13(h)(2).

(h) When it becomes necessary to supplement CEMS data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Method 6 of appendix A of this part shall be used to determine the SO_2concentration at the same location as the SO_2monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 of appendix A of this part shall be used to determine the NO_Xconcentration at the same location as the NO_Xmonitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2or CO_2concentration at the same location as the O_2or CO_2monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 of appendix A of this part shall be used to compute each 1-hour average concentration in ng/J (lb/MMBtu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under §60.13(c) and calibration checks under §60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 3B, 6, and 7 of appendix A of this part shall be used to determine O_2, SO_2, and NO_Xconcentrations, respectively.

(2) SO_2or NO_X(NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a CEMS for measuring opacity is between 60 and 80 percent. Span values for a CEMS measuring NO_Xshall be determined using one of the following procedures:

(i) Except as provided under paragraph (i)(3)(ii) of this section, NO_Xspan values shall be determined as follows:

Fossil fuel	Span values for NO_X (ppm)
Gas	500.

Liquid	500.
Solid	1,000.
Combination	500 (x + y) + 1,000z.

Where:

x = Fraction of total heat input derived from gaseous fossil fuel,

y = Fraction of total heat input derived from liquid fossil fuel, and

z = Fraction of total heat input derived from solid fossil fuel.

(ii) As an alternative to meeting the requirements of paragraph (i)(3)(i) of this section, the owner or operator of an affected facility may elect to use the NO_X span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(4) All span values computed under paragraph (i)(3)(i) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (i)(3)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel and determining span values under paragraph (i)(3)(i) of this section, the span value of the SO_2 CEMS at the inlet to the SO_2 control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the SO_2 control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired. For affected facilities determining span values under paragraph (i)(3)(ii) of this section, SO_2 span values shall be determined according to section 2.1.1 in appendix A to part 75 of this chapter.

(j) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 6 of appendix A of this part, Method 6A or 6B (whenever Methods 6 and 3 or 3B of appendix A of this part data are used) or 6C of appendix A of this part may be used. Each Method 6B of appendix A of this part sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B of appendix A of this part is used under paragraph (i) of this section, the conditions under §60.48Da(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7 of appendix A of this part, Method 7A, 7C, 7D, or 7E of appendix A of this part may be used. If Method 7C, 7D, or 7E of appendix A of this part is used, the sampling time for each run shall be 1 hour.

(3) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used if the sampling time is 1 hour.

(4) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used.

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under §60.44Da(d)(1).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in MWh on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 75 percent of the gross thermal output (measured relative to ISO conditions) of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard under §60.42Da, §60.43Da, §60.44Da, or §60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B of this part and the CD assessment, RATA and reporting provisions of procedure 1 of appendix F of this part, and record the output of the system, for measuring the volumetric flow rate of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of §75.20(c) of this chapter and appendix A to part 75 of this chapter, and continuing to meet the applicable quality control and quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, may be used. Flow rate data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of part 75 of this chapter.

(o) The owner or operator of a duct burner, as described in §60.41Da, which is subject to the NO_xstandards of §60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a CEMS to measure NO_xemissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

(p) The owner or operator of an affected facility demonstrating compliance with an Hg limit in §60.45Da shall install and operate a CEMS to measure and record the concentration of Hg in the exhaust gases from each stack according to the requirements in paragraphs (p)(1) through (p)(3) of this section. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality-assure the data from a Hg CEMS according to §75.10 of this chapter and appendices A and B to part 75 of this chapter, in lieu of following the procedures in paragraphs (p)(1) through (p)(3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in appendix B to this part.

(2) The owner or operator must conduct a performance evaluation of each CEMS according to the requirements of §60.13 and Performance Specification 12A in appendix B to this part.

(3) The owner or operator must operate each CEMS according to the requirements in paragraphs (p)(3)(i) through (iv) of this section.

(i) As specified in §60.13(e)(2), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) The owner or operator must reduce CEMS data as specified in §60.13(h).

(iii) The owner or operator shall use all valid data points collected during the hour to calculate the hourly average Hg concentration.

(iv) The owner or operator must record the results of each required certification and quality assurance test of the CEMS.

(4) Mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of this section.

(i) For each calendar month in which the affected unit operates, valid hourly Hg concentration data, stack gas volumetric flow rate data, moisture data (if required), and electrical output data (i.e., valid data for all of these parameters) shall be obtained for at least 75 percent of the unit operating hours in the month.

(ii) Data reported to meet the requirements of this subpart shall not include hours of unit startup, shutdown, or malfunction. In addition, for an affected facility that is also subject to subpart I of part 75 of this chapter, data reported to meet the requirements of this subpart shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(iii) If valid data are obtained for less than 75 percent of the unit operating hours in a month, you must discard the data collected in that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(iv) Notwithstanding the requirements of paragraph (p)(4)(iii) of this section, if valid data are obtained for less than 75 percent of the unit operating hours in another month in that same 12-month rolling average cycle, discard the data collected in that month and replace the data with the highest individual monthly emission rate determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator may use a sorbent trap monitoring system (as defined in §72.2 of this chapter) to monitor Hg concentration, according to the procedures described in §75.15 of this chapter and appendix K to part 75 of this chapter.

(r) For Hg CEMS that measure Hg concentration on a dry basis or for sorbent trap monitoring systems, the emissions data must be corrected for the stack gas moisture content. A certified continuous moisture monitoring system that meets the requirements of §75.11(b) of this chapter is acceptable for this purpose. Alternatively, the appropriate default moisture value, as specified in §75.11(b) or §75.12(b) of this chapter, may be used.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (*e.g.* , on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (*e.g.,* calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of §60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of §60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing recordkeeping and reporting procedures in accordance with the requirements of this subpart.

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under §60.42Da(c)(1) shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected source demonstrating compliance with the input-based emission limitation under §60.42Da(c)(2) may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) An owner or operator of an affected source that meets the conditions in either paragraph (u)(1), (2) or (3) of this section is exempted from the continuous opacity monitoring system requirements in paragraph (a) of this section and the monitoring requirements in §60.48Da(o).

(1) A CEMS for measuring PM emissions is used to demonstrate continuous compliance on a boiler operating day average with the emissions limitations under §60.42Da(a)(1) or §60.42Da(c)(2) and is installed, certified, operated, and maintained on the affected source according to the requirements of paragraph (v) of this section; or

(2) The affected source burns only gaseous fuels and does not use a post-combustion technology to reduce emissions of SO_2or PM; or

(3) The affected source does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (u)(3)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (u)(3)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each boiler operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly useful energy output from the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each boiler operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 1.4 lb/MWh, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 1.4 lb/MWh or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (u)(3) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 1.4 lb/MWh, and the date, time, and description of the corrective action.

(v) The owner or operator of an affected facility using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (v)(1) through (v)(3).

(1) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of §60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each relative accuracy test run of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2(or CO_2) data shall be collected concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using the following test methods.

(i) For PM, EPA Reference Method 5, 5B, or 17 of appendix A of this part shall be used.

(ii) For O_2(or CO_2), EPA Reference Method 3, 3A, or 3B of appendix A of this part, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(w)(1) Except as provided for under paragraphs (w)(2), (w)(3), and (w)(4) of this section, the SO_2, NO_X, CO_2, and O_2CEMS required under paragraphs (b) through (d) of this section shall be installed, certified, and operated in accordance with the applicable procedures in Performance Specification 2 or 3 in appendix B to this part or according to the procedures in appendices A and B to part 75 of this chapter. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with Procedure 1 in appendix F to this part, and a data assessment report (DAR), prepared according to section 7 of Procedure 1 in appendix F to this part, shall be submitted with each compliance report required under §60.51Da., the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(2) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For all required $CO_2$and O_2CEMS and for $SO_2$and NO_XCEMS with span values greater than 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F of this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to $SO_2$and NO_Xspan values less than 100 ppm;

(3) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For all required $CO_2$and O_2CEMS and for $SO_2$and NO_XCEMS with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for $SO_2$and NO_Xspan values less than or equal to 30 ppm;

(4) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For SO_2, CO_2, and O_2CEMS and for NO_XCEMS, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2(regardless of the SO_2emission level during the RATA), and for $NO_X$when the average NO_Xemission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu;

(5) If the owner or operator elects to implement the alternative data assessment procedures described in paragraphs (w)(2) through (w)(4) of this section, each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by paragraphs (w)(2) through (w)(4) of this section.

§ 60.50Da Compliance determination procedures and methods.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section for SO_2 and NO_X. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the PM standards in §60.42Da as follows:

(1) The dry basis F factor (O_2) procedures in Method 19 of appendix A of this part shall be used to compute the emission rate of PM.

(2) For the particular matter concentration, Method 5 of appendix A of this part shall be used at affected facilities without wet FGD systems and Method 5B of appendix A of this part shall be used after wet FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160±14 °C (320±25 °F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B of appendix A of this part shall be used to determine the O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2 traverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 concentrations at all traverse points.

(3) Method 9 of appendix A of this part and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO_2 standards in §60.43Da as follows:

(1) The percent of potential SO_2 emissions (%Ps) to the atmosphere shall be computed using the following equation:

$$\%P_s = \frac{(100 - \%R_f)(100 - \%R_g)}{100}$$

Where:

%Ps = Percent of potential SO_2 emissions, percent;

%Rf = Percent reduction from fuel pretreatment, percent; and

%Rg = Percent reduction by SO_2 control system, percent.

(2) The procedures in Method 19 of appendix A of this part may be used to determine percent reduction ($\%R_f$) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and fly ash interactions. This determination is optional.

(3) The procedures in Method 19 of appendix A of this part shall be used to determine the percent SO_2 reduction ($\%R_g$) of any SO_2 control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19 of appendix A of this part, may be used if the percent reduction is calculated using the average emission rate from the SO_2 control device and the average SO_2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate.

(5) The CEMS in §60.49Da(b) and (d) shall be used to determine the concentrations of SO_2 and CO_2 or O_2.

(d) The owner or operator shall determine compliance with the NO_X standard in §60.44Da as follows:

(1) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate of NO_X.

(2) The continuous monitoring system in §60.49Da(c) and (d) shall be used to determine the concentrations of $NO_X$and CO_2or O_2.

(e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 5 or 5B of appendix A of this part, Method 17 of appendix A of this part may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of §§2.1 and 2.3 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if it is used after wet FGD systems. Method 17 of appendix A of this part shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The $F_c$factor (CO_2) procedures in Method 19 of appendix A of this part may be used to compute the emission rate of PM under the stipulations of §60.46(d)(1). The CO_2shall be determined in the same manner as the O_2concentration.

(f) Electric utility combined cycle gas turbines are performance tested for PM, SO_2, and NO_Xusing the procedures of Method 19 of appendix A of this part. The $SO_2$and NO_Xemission rates from the gas turbine used in Method 19 of appendix A of this part calculations are determined when the gas turbine is performance tested under subpart GG of this part. The potential uncontrolled PM emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/MMBtu) heat input.

(g) For the purposes of determining compliance with the emission limits in §60.45Da, the owner or operator of an electric utility steam generating unit which is also a cogeneration unit shall use the procedures in paragraphs (g)(1) and (2) of this section to calculate emission rates based on electrical output to the grid plus 75 percent of the equivalent electrical energy (measured relative to ISO conditions) in the unit's process stream.

(1) All conversions from Btu/hr unit input to MW unit output must use equivalents found in 40 CFR 60.40(a)(1) for electric utilities (*i.e.* , 250 MMBtu/hr input to an electric utility steam generating unit is equivalent to 73 MW input to the electric utility steam generating unit); 73 MW input to the electric utility steam generating unit is equivalent to 25 MW output from the boiler electric utility steam generating unit; therefore, 250 MMBtu input to the electric utility steam generating unit is equivalent to 25 MW output from the electric utility steam generating unit).

(2) Use the Equation 5 in this section to determine the cogeneration Hg emission rate over a specific compliance period.

$$ER_{cogen} = \frac{M}{\left(V_{grid} + 0.75 \times V_{process}\right)} \qquad \text{(Eq. 5)}$$

Where:

ER_{cogen}= Cogeneration Hg emission rate over a compliance period in lb/MWh;

E = Mass of Hg emitted from the stack over the same compliance period (lb);

V_{grid}= Amount of energy sent to the grid over the same compliance period (MWh); and

$V_{process}$= Amount of energy converted to steam for process use over the same compliance period (MWh).

(h) The owner or operator shall determine compliance with the Hg limit in §60.45Da according to the procedures in paragraphs (h)(1) through (3) of this section.

(1) The initial performance test shall be commenced by the applicable date specified in §60.8(a). The required CEMS must be certified prior to commencing the test. The performance test consists of collecting hourly Hg emission data (lb/MWh) with the CEMS for 12 successive months of unit operation (excluding hours of unit startup, shutdown and malfunction). The average Hg emission rate is calculated for each month, and then the weighted, 12-month average Hg emission rate is calculated according to paragraph (h)(2) or (h)(3) of this section, as applicable. If, for any month in the initial performance test, the minimum data capture requirement in §60.49Da(p)(4)(i) is not met, the owner or operator shall report a substitute Hg emission rate for that month, as follows. For the first such month, the substitute

monthly Hg emission rate shall be the arithmetic average of all valid hourly Hg emission rates recorded to date. For any subsequent month(s) with insufficient data capture, the substitute monthly Hg emission rate shall be the highest valid hourly Hg emission rate recorded to date. When the 12-month average Hg emission rate for the initial performance test is calculated, for each month in which there was insufficient data capture, the substitute monthly Hg emission rate shall be weighted according to the number of unit operating hours in that month. Following the initial performance test, the owner or operator shall demonstrate compliance by calculating the weighted average of all monthly Hg emission rates (in lb/MWh) for each 12 successive calendar months, excluding data obtained during startup, shutdown, or malfunction.

(2) If a CEMS is used to demonstrate compliance, follow the procedures in paragraphs (h)(2)(i) through (iii) of this section to determine the 12-month rolling average.

(i) Calculate the total mass of Hg emissions over a month (M), in lb, using either Equation 6 in paragraph (h)(2)(i)(A) of this section or Equation 7 in paragraph (h)(2)(i)(B) of this section, in conjunction with Equation 8 in paragraph (h)(2)(i)(C) of this section.

(A) If the Hg CEMS measures Hg concentration on a wet basis, use Equation 6 below to calculate the Hg mass emissions for each valid hour:

$$E_h = KC_h Q_h t_h \qquad \text{(Eq. 6)}$$

Where:

E_h= Hg mass emissions for the hour, (lb);

K = Units conversion constant, 6.24×10^{-11} lb-scm/μgm-scf;

C_h= Hourly $H_g$concentration, wet basis, (μgm/scm);

Q_h= Hourly stack gas volumetric flow rate, (scfh); and

t_h= Unit operating time, i.e., the fraction of the hour for which the unit operated. For example, th = 0.50 for a half-hour of unit operation and 1.00 for a full hour of operation.

(B) If the Hg CEMS measures Hg concentration on a dry basis, use Equation 7 below to calculate the Hg mass emissions for each valid hour:

$$E_h = KC_h Q_h t_h (1 - B_{ws}) \qquad \text{(Eq. 7)}$$

Where:

E_h= Hg mass emissions for the hour, (lb);

K = Units conversion constant, 6.24×10^{-11}lb-scm/μgm-scf;

C_h= Hourly Hg concentration, dry basis, (μgm/dscm);

Q_h= Hourly stack gas volumetric flow rate, (scfh);

t_h= Unit operating time, *i.e.* , the fraction of the hour for which the unit operated; and

B_{ws}= Stack gas moisture content, expressed as a decimal fraction (*e.g.* , for 8 percent H_2O, B_{ws}= 0.08).

(C) Use Equation 8, below, to calculate M, the total mass of Hg emitted for the month, by summing the hourly masses derived from Equation 6 or 7 (as applicable):

$$M = \sum_{h=1}^{n} E_h \quad \text{(Eq. 8)}$$

Where:

M = Total Hg mass emissions for the month, (lb);

E_h= Hg mass emissions for hour "h", from Equation 6 or 7 of this section, (lb); and

n = Number of unit operating hours in the month with valid CE and electrical output data, excluding hours of unit startup, shutdown and malfunction.

(ii) Calculate the monthly Hg emission rate on an output basis (lb/MWh) using Equation 9, below. For a cogeneration unit, use Equation 5 in paragraph (g) of this section instead.

$$ER = \frac{M}{P} \quad \text{(Eq. 9)}$$

Where:

ER = Monthly Hg emission rate, (lb/MWh);

M = Total mass of Hg emissions for the month, from Equation 8, above, (lb); and

P = Total electrical output for the month, for the hours used to calculate M, (MWh).

(iii) Until 12 monthly Hg emission rates have been accumulated, calculate and report only the monthly averages. Then, for each subsequent calendar month, use Equation 10 below to calculate the 12-month rolling average as a weighted average of the Hg emission rate for the current month and the Hg emission rates for the previous 11 months, with one exception. Calendar months in which the unit does not operate (zero unit operating hours) shall not be included in the 12-month rolling average.

$$E_{avg} = \frac{\sum_{i=1}^{12} (ER_i \times n_i)}{\sum_{i=1}^{12} n_i} \quad \text{(Eq. 10)}$$

Where:

E_{avg}= Weighted 12-month rolling average Hg emission rate, (lb/MWh);

ER_i= Monthly Hg emission rate, for month "i", (lb/MWh); and

n = Number of unit operating hours in month "i" with valid CEM and electrical output data, excluding hours of unit startup, shutdown, and malfunction.

(3) If a sorbent trap monitoring system is used in lieu of a Hg CEMS, as described in §75.15 of this chapter and in appendix K to part 75 of this chapter, calculate the monthly Hg emission rates using Equations 7 through 9 of this section, except that for a particular pair of sorbent traps, $C_h$in Equation 7 shall be the flow-proportional average Hg concentration measured over the data collection period.

(i) Daily calibration drift (CD) tests and quarterly accuracy determinations shall be performed for Hg CEMS in accordance with Procedure 1 of appendix F to this part. For the CD assessments, you may use either elemental mercury or mercuric chloride ($Hg°$ $HgCl_2$) standards. The four quarterly accuracy determinations shall consist of one RATA and three measurement error (ME) tests using $HgCl_2$standards, as described in section 8.3 of Performance

Specification 12–A in appendix B to this part (note: Hg° standards may be used if the Hg monitor does not have a converter). Alternatively, the owner or operator may implement the applicable daily, weekly, quarterly, and annual quality assurance (QA) requirements for Hg CEMS in appendix B to part 75 of this chapter, in lieu of the QA procedures in appendices B and F to this part. Annual RATA of sorbent trap monitoring systems shall be performed in accordance with appendices A and B to part 75 of this chapter, and all other quality assurance requirements specified in appendix K to part 75 of this chapter shall be met for sorbent trap monitoring systems.

§ 60.51Da Reporting requirements.

(a) For SO_2, NO_X, PM, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For $SO_2$and $NO_X$the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average $SO_2$and NO_Xemission rates (ng/J or lb/MMBtu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of $SO_2$for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_Xonly), emergency conditions (SO_2only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(9) Description of any modifications to CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by §60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of §60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (no) and inlet emission rates (n_i) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (E_o*) and the upper confidence limit for the mean inlet emission rate (E_i*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}) as applicable.

(d) If any standards under §60.43Da are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under §60.48Da(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the SO_2emission standard under §60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of §60.50Da and Method 19 of appendix A of this part; and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, SO_2or NO_Xemissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) For Hg, the following information shall be reported to the Administrator:

(1) Company name and address;

(2) Date of report and beginning and ending dates of the reporting period;

(3) The applicable Hg emission limit (lb/MWh); and

(4) For each month in the reporting period:

(i) The number of unit operating hours;

(ii) The number of unit operating hours with valid data for Hg concentration, stack gas flow rate, moisture (if required), and electrical output;

(iii) The monthly Hg emission rate (lb/MWh);

(iv) The number of hours of valid data excluded from the calculation of the monthly Hg emission rate, due to unit startup, shutdown and malfunction; and

(v) The 12-month rolling average Hg emission rate (lb/MWh); and

(5) The data assessment report (DAR) required by appendix F to this part, or an equivalent summary of QA test results if the QA of part 75 of this chapter are implemented.

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(i) For the purposes of the reports required under §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) The owner or operator of an affected facility may submit electronic quarterly reports for $SO_2$and/or $NO_X$and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

§ 60.52Da Recordkeeping requirements.

The owner or operator of an affected facility subject to the emissions limitations in §60.45Da shall provide notifications in accordance with §60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of §60.7(f).

Appendix B

40 CFR Part 60, Subpart Y – *Standards of Performance for Coal Preparation Plants*

Subpart Y—Standards of Performance for Coal Preparation Plants

§ 60.250 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to any of the following affected facilities in coal preparation plants which process more than 181 Mg (200 tons) per day: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 24, 1974, is subject to the requirements of this subpart.

[42 FR 37938, July 25, 1977; 42 FR 44812, Sept. 7, 1977, as amended at 65 FR 61757, Oct. 17, 2000]

§ 60.251 Definitions.

As used in this subpart, all terms not defined herein have the meaning given them in the Act and in subpart A of this part.

(a) *Coal preparation plant* means any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

(b) *Bituminous coal* means solid fossil fuel classified as bituminous coal by ASTM Designation D388–77, 90, 91, 95, or 98a (incorporated by reference—see §60.17).

(c) *Coal* means all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM Designation D388–77, 90, 91, 95, or 98a (incorporated by reference—see §60.17).

(d) *Cyclonic flow* means a spiraling movement of exhaust gases within a duct or stack.

(e) *Thermal dryer* means any facility in which the moisture content of bituminous coal is reduced by contact with a heated gas stream which is exhausted to the atmosphere.

(f) *Pneumatic coal-cleaning equipment* means any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

(g) *Coal processing and conveying equipment* means any machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery. This includes, but is not limited to, breakers, crushers, screens, and conveyor belts.

(h) *Coal storage system* means any facility used to store coal except for open storage piles.

(i) *Transfer and loading system* means any facility used to transfer and load coal for shipment.

[41 FR 2234, Jan. 15, 1976, as amended at 48 FR 3738, Jan. 27, 1983; 65 FR 61757, Oct. 17, 2000]

§ 60.252 Standards for particulate matter.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any thermal dryer gases which:

(1) Contain particulate matter in excess of 0.070 g/dscm (0.031 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by §60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any pneumatic coal cleaning equipment, gases which:

(1) Contain particulate matter in excess of 0.040 g/dscm (0.017 gr/dscf).

(2) Exhibit 10 percent opacity or greater.

(c) On and after the date on which the performance test required to be conducted by §60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

[41 FR 2234, Jan. 15, 1976, as amended at 65 FR 61757, Oct. 17, 2000]

§ 60.253 Monitoring of operations.

(a) The owner or operator of any thermal dryer shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(1) A monitoring device for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within ±1.7 °C (±3 °F).

(2) For affected facilities that use venturi scrubber emission control equipment:

(i) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gauge.

(ii) A monitoring device for the continuous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply pressure. The pressure sensor or tap must be located close to the water discharge point. The Administrator may be consulted for approval of alternative locations.

(b) All monitoring devices under paragraph (a) of this section are to be recalibrated annually in accordance with procedures under §60.13(b).

[41 FR 2234, Jan. 15, 1976, as amended at 54 FR 6671, Feb. 14, 1989; 65 FR 61757, Oct. 17, 2000]

§ 60.254 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the particular matter standards in §60.252 as follows:

(1) Method 5 shall be used to determine the particulate matter concentration. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin.

(2) Method 9 and the procedures in §60.11 shall be used to determine opacity.

[54 FR 6671, Feb. 14, 1989]

Appendix C

40 CFR Part 60, Subpart IIII – *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

What This Subpart Covers

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (3) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines,

(ii) The model year listed in table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are:

(i) Manufactured after April 1, 2006 and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of stationary CI ICE that modify or reconstruct their stationary CI ICE after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

Emission Standards for Manufacturers

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

§ 60.4203 How long must my engines meet the emission standards if I am a stationary CI internal combustion engine manufacturer?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the useful life of the engines.

Emission Standards for Owners and Operators

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Reduce nitrogen oxides (NO_X) emissions by 90 percent or more, or limit the emissions of NO_Xin the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (g/KW-hr) (1.2 grams per HP-hour (g/HP-hr)).

(2) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (d)(1) and (2) of this section.

(1) Reduce NO_Xemissions by 90 percent or more, or limit the emissions of NO_Xin the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (1.2 grams per HP-hour).

(2) Reduce PM emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(c) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of this section beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(d) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the Federal Aid Highway System may petition the Administrator for approval to use any fuels mixed with used lubricating oil that do not meet the fuel requirements of paragraphs (a) and (b) of this section. Owners and operators must demonstrate in their petition to the Administrator that there is no other place to use the lubricating oil. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

Other Requirements for Owners and Operators

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in the previous model year?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (f) of this section after the dates specified in paragraphs (a) through (f) of this section.

(h) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Compliance Requirements

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and §60.4202(c) using the certification procedures required in 40 CFR part 94 subpart C, and must test their engines as specified in 40 CFR part 94.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 40 CFR 1039.125, 40 CFR 1039.130, 40 CFR 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89 or 40 CFR part 94 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate, but the words "stationary" must be included instead of "nonroad" or "marine" on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under parts 89, 94, or 1039 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words "and stationary" after the word "nonroad" or "marine," as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as "Fire Pump Applications Only".

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and $NO_x$and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit $NO_x$and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited.

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (d) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (d) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i= concentration of NO_X or PM at the control device inlet,

C_o= concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_X or PM emissions.

(2) You must normalize the NO_X or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \%\,O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj}= Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$= Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209_{F_d}}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o= Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d= Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

F_c= Ratio of the volume of CO_2produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

(ii) Calculate the CO_2correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2}= CO_2correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2correction value, percent.

(iii) Calculate the $NO_X$and PM gas concentrations adjusted to 15 percent O_2using CO_2as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj}= Calculated NO_Xor PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_Xor PM, uncorrected.

$\%CO_2$= Measured CO_2concentration, dry basis, percent.

(e) To determine compliance with the NO_Xmass per unit output emission limitation, convert the concentration of NO_Xin the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d= Measured NO_Xconcentration in ppm.

1.912×10^{-3}= Conversion constant for ppm $NO_X$to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj}= Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

Notification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Special Requirements

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §60.4205. Non-emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder, must meet the applicable emission standards in §60.4204(c).

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in §60.4207.

§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI engines located in areas of Alaska not accessible by the Federal Aid Highway System should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) The Governor of Alaska may submit for EPA approval, by no later than January 11, 2008, an alternative plan for implementing the requirements of 40 CFR part 60, subpart IIII, for public-sector electrical utilities located in rural areas of Alaska not accessible by the Federal Aid Highway System. This alternative plan must be based on the requirements of section 111 of the Clean Air Act including any increased risks to human health and the environment and must also be based on the unique circumstances related to remote power generation, climatic conditions, and serious economic impacts resulting from implementation of 40 CFR part 60, subpart IIII. If EPA approves by rulemaking process an alternative plan, the provisions as approved by EPA under that plan shall apply to the diesel engines used in new stationary internal combustion engines subject to this paragraph.

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

(a) Owners and operators of stationary CI ICE that do not use diesel fuel, or who have been given authority by the Administrator under §60.4207(d) of this subpart to use fuels that do not meet the fuel requirements of paragraphs (a) and (b) of §60.4207, may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4202 or §60.4203 using such fuels.

(b) [Reserved]

General Provisions

§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Definitions

§ 60.4219 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary CI ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.

Engine manufacturer means the manufacturer of the engine. See the definition of "manufacturer" in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means either:

(1) The calendar year in which the engine was originally produced, or

(2) The annual new model production period of the engine manufacturer if it is different than the calendar year. This must include January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year. For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was originally produced.

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

Useful life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for useful life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for useful life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007–2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	$NMHC + NO_X$	HC	NO_X	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_X+ NMHC	CO	PM
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

[As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:]

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)

19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

[1]For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2]For model years 2010–2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3]In model years 2009–2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed[1]	Torque (percent)[2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1]Engine speed: ±2 percent of point.

[2]Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

[As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:]

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device;	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63,	(c) Measurements to determine moisture content must be made at the same time as the

		and,	appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	measurements for NO_X concentration.
		iv. Measure NO_X at the inlet and outlet of the control device	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and,	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.
		iv. Measure NO_X at the exhaust of the stationary	(4) Method 7E of 40 CFR part 60, appendix A,	(d) NO_X concentration must be at 15 percent

		internal combustion engine	Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary	(2) Method 3, 3A, or 3B of 40 CFR part 60,	(b) Measurements to determine O_2concentration

		internal combustion engine exhaust at the sampling port location; and	appendix A	must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to

			stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

Appendix D

40 CFR Part 63, Subpart ZZZZ – *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Source: 69 FR 33506, June 15, 2004, unless otherwise noted.

What This Subpart Covers

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008]

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraph (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(h).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions; or

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(h) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) A stationary RICE which is an existing spark ignition 4 stroke rich burn (4SRB) stationary RICE located at an area source, an existing spark ignition 4SRB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source, an existing spark ignition 2 stroke lean burn (2SLB) stationary RICE, an existing spark ignition 4 stroke lean burn (4SLB) stationary RICE, an existing compression ignition (CI) stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, does not have to meet the requirements of this subpart and of subpart A of this part. No initial notification is necessary.

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that is a new or reconstructed stationary RICE located at an area source, or is a new or reconstructed stationary RICE located at a major source of HAP emissions and is a spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of less than 500 brake HP, a spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of less than 250 brake HP, or a 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP, a stationary RICE with a site rating of less than or equal to 500 brake HP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP, or a compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP, must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008]

§ 63.6595 When do I have to comply with this subpart?

(a) *Affected Sources.* (1) If you have an existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than June 15, 2007.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008]

Emission and Operating Limitations

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a and 2a to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE, an existing 4SLB stationary RICE, or an existing CI stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

[73 FR 3605, Jan. 18, 2008]

§ 63.6601 What emission limitations must I meet if I own or operate a 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008]

General Compliance Requirements

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations in this subpart that apply to you at all times, except during periods of startup, shutdown, and malfunction.

(b) If you must comply with emission limitations and operating limitations, you must operate and maintain your stationary RICE, including air pollution control and monitoring equipment, in a manner consistent with good air pollution control practices for minimizing emissions at all times, including during startup, shutdown, and malfunction.

Testing and Initial Compliance Requirements

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008]

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements in §63.7(e)(1) and under the specific conditions that this subpart specifies in Table 4. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

(c) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §63.7(e)(1).

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 1)}$$

Where:

C_i= concentration of CO or formaldehyde at the control device inlet,

C_o= concentration of CO or formaldehyde at the control device outlet, and

R = percent reduction of CO or formaldehyde emissions.

(2) You must normalize the carbon monoxide (CO) or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2concentration is measured in lieu of oxygen concentration measurement, a CO_2correction factor is needed. Calculate the CO_2correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific $F_o$value for the fuel burned during the test using values obtained from Method 19, section 5.2, and the following equation:

$$F_o = \frac{0.209\, F_d}{F_c} \qquad \text{(Eq. 2)}$$

Where:

F_o= Fuel factor based on the ratio of oxygen volume to the ultimate CO_2volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d= Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

F_c= Ratio of the volume of CO_2produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

(ii) Calculate the CO_2correction factor for correcting measurement data to 15 percent oxygen, as follows:

$$X_{co_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 3)}$$

Where:

X_{co2}= CO_2correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2correction value, percent.

(iii) Calculate the $NO_x$and SO_2gas concentrations adjusted to 15 percent O_2using CO_2as follows:

$$C_{adj} = C_d \frac{X_{co_2}}{\%CO_2} \qquad \text{(Eq. 4)}$$

Where:

$\%CO_2$= Measured CO_2concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

§ 63.6625 What are my monitoring, installation, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either oxygen or CO_2at both the inlet and the outlet of the control device according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in §63.8.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008]

§ 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

Continuous Compliance Requirements

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously at all times that the stationary RICE is operating.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Tables 1a and 1b and Tables 2a and 2b of this subpart that apply to you according to methods specified in Table 6 of this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b and Tables 2a and 2b of this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) [Reserved]

(d) Consistent with §§63.6(e) and 63.7(e)(1), deviations from the emission or operating limitations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Administrator's satisfaction that you were operating in accordance with §63.6(e)(1). For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations.

Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR §94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate any stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing CI stationary RICE, an existing emergency stationary RICE, an existing limited use emergency stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008]

Notifications, Reports, and Records

§ 63.6645 What notifications must I submit and when?

(a) If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions or a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions, you must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

[73 FR 3606, Jan. 18, 2008]

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) The first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) Each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a startup, shutdown, or malfunction during the reporting period, the compliance report must include the information in §63.10(d)(5)(i).

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR

71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(3), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) The records in §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form on-site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off-site for the remaining 3 years.

Other Requirements and Information

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate any stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions: An existing 2SLB RICE, an existing 4SLB stationary RICE, an existing CI stationary RICE, an existing stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[73 FR 3606, Jan. 18, 2008]

§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in §63.6610(b).

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.*, as amended by Public Law 101–549, 104 Stat. 2399).

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary RICE whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc. Stationary RICE used for peak shaving are not considered emergency stationary RICE. Stationary ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines. Emergency stationary RICE with a site-rating of more than 500 brake HP located at a major source of HAP emissions that were installed prior to June 12, 2006, may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance. Emergency stationary RICE with a site-rating of more than 500 brake HP located at a major source of HAP emissions that were installed prior to June 12, 2006, may also operate an additional 50 hours per year in non-emergency situations. Emergency stationary RICE with a site-rating of more than 500 brake HP located at a major source of HAP emissions that were installed on or after June 12, 2006, must comply with requirements specified in 40 CFR 60.4243(d).

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes "rich" glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The "lean" glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X(such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008]

Table1ato Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

[As stated in §63.6600, you must comply with the following emission limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions at 100 percent load plus or minus 10 percent]

For each...	You must meet the following emission limitations...
1. 4SRB stationary RICE	a. reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007;
	or
	b. limit the concentration of formaldehyde in the stationary RICE exhaust 350 ppbvd or less at 15 percent O_2.

[73 FR 3607, Jan. 18, 2008]

Table1bto Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

[As stated in §§63.6600, 63.6630 and 63.6640, you must comply with the following operating emission limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions]

For each...	You must meet the following operating limitation...
1. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and
4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent $O_2$and using NSCR.	b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.
2. 4SRB stationary RICE complying	Comply with any operating limitations approved

with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or	by the Administrator.
4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent $O_2$and not using NSCR.	

[73 FR 3607, Jan. 18, 2008]

Table2ato Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

[As stated in §§63.6600 and 63.6601, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent]

For each...	You must meet the following emission limitation...
1. 2SLB stationary RICE	a. reduce CO emissions by 58 percent or more;
	or
	b. limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2until June 15, 2007.
2. 4SLB stationary RICE	a. reduce CO emissions by 93 percent or more;
	or
	b. limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2.
3. CI stationary RICE	a. reduce CO emissions by 70 percent or more;
	or

	b. limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2.

[73 FR 3608, Jan. 18, 2008]

Table2bto Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and 4SLB Burn Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

[As stated in §§63.6600, 63.6601, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary]

For each...	You must meet the following operating limitation...
1. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.
2. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and not using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst	Comply with any operating limitations approved by the Administrator.

[73 FR 3608, Jan. 18, 2008]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

[As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements]

For each . . .	Complying with the requirement to . . .	You must . . .
1. 2SLB and 4SLB stationary	Reduce CO emissions and	Conduct subsequent

RICE and CI stationary RICE	not using a CEMS	performance tests semiannually.[1]
2. 4SRB stationary RICE with a brake horsepower ≥5,000	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE (all stationary RICE subcategories and all brake horsepower ratings)	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]

[1]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

[As stated in §§63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE]

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. Reduce CO emissions	i. Measure the O_2at the inlet and outlet of the control device; and	(1) Portable CO and O_2analyzer	(a) Using ASTM D6522–00 (2005)[a](incorporated by reference, see §63.14). Measurements to determine O2 must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the control device	(1) Portable CO and O_2analyzer	(a) Using ASTM D6522–00 (2005)[a](incorporated by reference, see §63.14) or Method 10 of 40 CFR, appendix A. The CO concentration must be at 15 percent O2, dry basis.
2. 4SRB stationary RICE	a. Reduce formaldehyde emissions	i. Select the sampling port location and the number of	(1) Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i)	(a) Sampling sites must be located at the inlet and outlet of the control device.

		traverse points; and		
		ii. Measure O2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (2005).	(a) Measurements to determine O2 concentration must be made at the same time as the measurements for formaldehyde concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03[b], provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde in the stationary RICE exhaust	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i)	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O2 concentration of the stationary	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method	(a) Measurements to determine O2 concentration must be made at the same time and location as the

		RICE exhaust at the sampling port location; and	D6522–00 (2005)	measurements for formaldehyde concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03[b], provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[a]You may also use Methods 3A and 10 as options to ASTM–D6522–00 (2005). You may obtain a copy of ASTM–D6522–00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[b]You may obtain a copy of ASTM–D6348–03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[73 FR 3609, Jan. 18, 2008]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations and Operating Limitations

[As stated in §§63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following]

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. 2SLB and	a. Reduce CO emissions	i. the average reduction of emissions of CO

4SLB stationary RICE and CI stationary RICE	and using oxidation catalyst, and using a CPMS	determined from the initial performance test achieves the required CO percent reduction; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. 2SLB and 4SLB stationary RICE and CI stationary RICE	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
3. 2SLB and 4SLB stationary RICE and CI stationary RICE	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and
		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
4. 4SRB	a. Reduce formaldehyde	i. The average reduction of emissions of

stationary RICE	emissions and using NSCR	formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
5. 4SRB stationary RICE	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
6. Stationary RICE	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
7. Stationary RICE	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and

		iii. You have recorded the approved operating parameters (if any) during the initial performance test.

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations and Operating Limitations

[As stated in §63.6640, you must continuously comply with the emissions and operating limitations as required by the following]

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. 2SLB and 4SLB stationary RICE and CI stationary RICE	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[1]; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. 2SLB and 4SLB stationary RICE and CI stationary RICE	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[1]; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations

		for the operating parameters established during the performance test.
3. 2SLB and 4SLB stationary RICE and CI stationary RICE	a. Reduce CO emissions and using a CEMS	i. Collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction of CO emissions according to §63.6620; and
		ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period; and
		iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. 4SRB stationary RICE	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. 4SRB stationary RICE	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		ii. reducing these data to 4-hour rolling averages;
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

6. 4SRB stationary RICE with a brake horsepower ≥5,000	Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved[1].
7. Stationary RICE	Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[1]; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. Stationary RICE	Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[1]; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

[1]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not

in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

[As stated in §63.6650, you must comply with the following requirements for reports]

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or	i. Semiannually according to the requirements in §63.6650(b).
	b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or	i. Semiannually according to the requirements in §63.6650(b).
	c. If you had a startup, shutdown or malfunction during the reporting period, the information in §63.10(d)(5)(i)	i. Semiannually according to the requirements in §63.6650(b).
2. An immediate startup, shutdown, and malfunction report if actions addressing the startup, shutdown, or malfunction were inconsistent with your startup, shutdown, or malfunction plan during	a. Actions taken for the event; and	i. By fax or telephone within 2 working days after starting actions inconsistent with the plan.

the reporting period		
	b. The information in §63.10(d)(5)(ii).	i. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authorities. (§63.10(d)(5)(ii))
3. Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in §63.6650.
	b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 3.a.i.
	c. Any problems or errors suspected with the meters	i. See item 3.a.i.

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ

[As stated in §63.6665, you must comply with the following applicable general provisions]

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.1	General applicability of the General Provisions	Yes	
§63.2	Definitions	Yes	Additional terms defined in §63.6675.
§63.3	Units and abbreviations	Yes	
§63.4	Prohibited activities and circumvention	Yes	
§63.5	Construction and reconstruction	Yes	
§63.6(a)	Applicability	Yes	

§63.6(b)(1)–(4)	Compliance dates for new and reconstructed sources	Yes	
§63.6(b)(5)	Notification	Yes	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes	
§63.6(c)(1)–(2)	Compliance dates for existing sources	Yes	
§63.6(c)(3)–(4)	[Reserved]		
§36.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes	
§63.6(d)	[Reserved]		
§63.6(e)(1)	Operation and maintenance	Yes	
§63.6(e)(2)	[Reserved]		
§63.6(e)(3)	Startup, shutdown, and malfunction plan	Yes	
§63.6(f)(1)	Applicability of standards except during startup shutdown malfunction (SSM)	Yes	
§63.6(f)(2)	Methods for determining compliance	Yes	
§63.6(f)(3)	Finding of compliance	Yes	
§63.6(g)(1)–(3)	Use of alternate standard	Yes	
§63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes	
§63.6(j)	Presidential compliance exemption	Yes	
§63.7(a)(1)–(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at

			§§63.6610 and 63.6611.
§63.7(a)(3)	CAA section 114 authority	Yes	
§63.7(b)(1)	Notification of performance test	Yes	
§63.7(b)(2)	Notification of rescheduling	Yes	
§63.7(c)	Quality assurance/test plan	Yes	
§63.7(d)	Testing facilities	Yes	
§63.7(e)(1)	Conditions for conducting performance tests	Yes	
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at §63.6620.
§63.7(e)(3)	Test run duration	Yes	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes	
§63.7(f)	Alternative test method provisions	Yes	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes	
§63.7(h)	Waiver of tests	Yes	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.
§63.8(a)(2)	Performance specifications	Yes	
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring for control devices	No	
§63.8(b)(1)	Monitoring	Yes	
§63.8(b)(2)–(3)	Multiple effluents and multiple monitoring systems	Yes	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes	

§63.8(c)(1)(i)	Routine and predictable SSM	Yes	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	Yes	
§63.8(c)(2)–(3)	Monitoring system installation	Yes	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)–(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§63.8(d)	CMS quality control	Yes	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
§63.8(f)(1)–(5)	Alternative monitoring method	Yes	
§63.8(f)(6)	Alternative to relative accuracy test	Yes	
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements	Yes	
§63.9(b)(1)–(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
§63.9(c)	Request for compliance extension	Yes	
§63.9(d)	Notification of special	Yes	

	compliance requirements for new sources		
§63.9(e)	Notification of performance test	Yes	
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	
§63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
§63.9(h)(1)–(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
§63.9(i)	Adjustment of submittal deadlines	Yes	
§63.9(j)	Change in previous information	Yes	
§63.10(a)	Administrative provisions for record keeping/reporting	Yes	
§63.10(b)(1)	Record retention	Yes	
§63.10(b)(2)(i)–(v)	Records related to SSM	Yes	
§63.10(b)(2)(vi)–(xi)	Records	Yes	
§63.10(b)(2)(xii)	Record when under waiver	Yes	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes	

§63.10(b)(3)	Records of applicability determination	Yes	
§63.10(c)	Additional records for sources using CEMS	Yes	Except that §63.10(c)(2)–(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes	
§63.10(d)(2)	Report of performance test results	Yes	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	Yes	
§63.10(e)(1) and (2)(i)	Additional CMS reports	Yes	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes	Except that §63.10(e)(3)(i)(C) is reserved.
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes	
§63.11	Flares	No	
§63.12	State authority and delegations	Yes	
§63.13	Addresses	Yes	
§63.14	Incorporation by reference	Yes	
§63.15	Availability of information	Yes	

[73 FR 3610, Jan. 18, 2008]

Appendix E

Arkansas Continuous Emission Monitoring Systems Conditions

Appendix E

Arkansas Department of Environmental Quality

CONTINUOUS EMISSION MONITORING SYSTEMS CONDITIONS

Revised August 2004

Appendix E

PREAMBLE

These conditions are intended to outline the requirements for facilities required to operate Continuous Emission Monitoring Systems/Continuous Opacity Monitoring Systems (CEMS/COMS). Generally there are three types of sources required to operate CEMS/COMS:

1. CEMS/COMS required by 40 CFR Part 60 or 63,
2. CEMS required by 40 CFR Part 75,
3. CEMS/COMS required by ADEQ permit for reasons other that Part 60, 63 or 75.

These CEMS/COMS conditions are not intended to supercede Part 60, 63 or 75 requirements.

- Only CEMS/COMS in the third category (those required by ADEQ permit for reasons other than Part 60, 63, or 75) shall comply with SECTION II, MONITORING REQUIREMENTS and SECTION IV, QUALITY ASSURANCE/QUALITY CONTROL.

- All CEMS/COMS shall comply with Section III, NOTIFICATION AND RECORDKEEPING.

SECTION I

DEFINITIONS

Continuous Emission Monitoring System (CEMS) - The total equipment required for the determination of a gas concentration and/or emission rate so as to include sampling, analysis and recording of emission data.

Continuous Opacity Monitoring System (COMS) - The total equipment required for the determination of opacity as to include sampling, analysis and recording of emission data.

Calibration Drift (CD) - The difference in the CEMS output reading from the established reference value after a stated period of operation during which no unscheduled maintenance, repair, or adjustments took place.

Back-up CEMS (Secondary CEMS) - A CEMS with the ability to sample, analyze and record stack pollutant to determine gas concentration and/or emission rate. This CEMS is to serve as a back-up to the primary CEMS to minimize monitor downtime.

Excess Emissions - Any period in which the emissions exceed the permit limits.

Monitor Downtime - Any period during which the CEMS/COMS is unable to sample, analyze and record a minimum of four evenly spaced data points over an hour, except during one daily zero-span check during which two data points per hour are sufficient.

Out-of-Control Period - Begins with the time corresponding to the completion of the fifth, consecutive, daily CD check with a CD in excess of two times the allowable limit, or the time corresponding to the completion of the daily CD check preceding the daily CD check that results in a CD in excess of four times the allowable limit and the time corresponding to the completion of the sampling for the RATA, RAA, or CGA which exceeds the limits outlined in Section IV. Out-of-Control Period ends with the time corresponding to the completion of the CD check following corrective action with the results being within the allowable CD limit or the completion of the sampling of the subsequent successful RATA, RAA, or CGA.

Primary CEMS - The main reporting CEMS with the ability to sample, analyze, and record stack pollutant to determine gas concentration and/or emission rate.

Relative Accuracy (RA) - The absolute mean difference between the gas concentration or emission rate determined by the CEMS and the value determined by the reference method plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the reference method tests of the applicable emission limit.

Span Value – The upper limit of a gas concentration measurement range.

SECTION II

MONITORING REQUIREMENTS

A. For new sources, the installation date for the CEMS/COMS shall be no later than thirty (30) days from the date of start-up of the source.

B. For existing sources, the installation date for the CEMS/COMS shall be no later than sixty (60) days from the issuance of the permit unless the permit requires a specific date.

C. Within sixty (60) days of installation of a CEMS/COMS, a performance specification test (PST) must be completed. PST's are defined in 40 CFR, Part 60, Appendix B, PS 1-9. The Department may accept alternate PST's for pollutants not covered by Appendix B on a case-by-case basis. Alternate PST's shall be approved, in writing, by the ADEQ CEM Coordinator prior to testing.

D. Each CEMS/COMS shall have, as a minimum, a daily zero-span check. The zero-span shall be adjusted whenever the 24-hour zero or 24-hour span drift exceeds two times the limits in the applicable performance specification in 40 CFR, Part 60, Appendix B. Before any adjustments are made to either the zero or span drifts measured at the 24-hour interval the excess zero and span drifts measured must be quantified and recorded.

E. All CEMS/COMS shall be in continuous operation and shall meet minimum frequency of operation requirements of 95% up-time for each quarter for each pollutant measured. Percent of monitor down-time is calculated by dividing the total minutes the monitor is not in operation by the total time in the calendar quarter and multiplying by one hundred. Failure to maintain operation time shall constitute a violation of the CEMS conditions.

F. Percent of excess emissions are calculated by dividing the total minutes of excess emissions by the total time the source operated and multiplying by one hundred. Failure to maintain compliance may constitute a violation of the CEMS conditions.

G. All CEMS measuring emissions shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive fifteen minute period unless more cycles are required by the permit. For each CEMS, one-hour averages shall be computed from four or more data points equally spaced over each one hour period unless more data points are required by the permit.

H. All COMS shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

I. When the pollutant from a single affected facility is released through more than one point, a CEMS/COMS shall be installed on each point unless installation of fewer systems is approved, in writing, by the ADEQ CEM Coordinator. When more than one CEM/COM is used to monitor emissions from one affected facility the owner or operator shall report the results as required from each CEMS/COMS.

SECTION III

NOTIFICATION AND RECORD KEEPING

A. When requested to do so by an owner or operator, the ADEQ CEM Coordinator will review plans for installation or modification for the purpose of providing technical advice to the owner or operator.

B. Each facility which operates a CEMS/COMS shall notify the ADEQ CEM Coordinator of the date for which the demonstration of the CEMS/COMS performance will commence (i.e. PST, RATA, RAA, CGA). Notification shall be received in writing no less than 15 days prior to testing. Performance test results shall be submitted to the Department within thirty days after completion of testing.

C. Each facility which operates a CEMS/COMS shall maintain records of the occurrence and duration of start up/shut down, cleaning/soot blowing, process problems, fuel problems, or other malfunction in the operation of the affected facility which causes excess emissions. This includes any malfunction of the air pollution control equipment or any period during which a continuous monitoring device/system is inoperative.

D. Except for Part 75 CEMs, each facility required to install a CEMS/COMS shall submit an excess emission and monitoring system performance report to the Department (Attention: Air Division, CEM Coordinator) at least quarterly, unless more frequent submittals are warranted to assess the compliance status of the facility. Quarterly reports shall be postmarked no later than the 30th day of the month following the end of each calendar quarter. Part 75 CEMs shall submit this information semi-annually and as part of Title V six (6) month reporting requirement if the facility is a Title V facility.

E. All excess emissions shall be reported in terms of the applicable standard. Each report shall be submitted on ADEQ Quarterly Excess Emission Report Forms. Alternate forms may be used with prior written approval from the Department.

F. Each facility which operates a CEMS/COMS must maintain on site a file of CEMS/COMS data including all raw data, corrected and adjusted, repair logs, calibration checks, adjustments, and test audits. This file must be retained for a period of at least five years, and is required to be maintained in such a condition that it can easily be audited by an inspector.

G. Except for Part 75 CEMs, quarterly reports shall be used by the Department to determine compliance with the permit. For Part 75 CEMs, the semi-annual report shall be used.

SECTION IV

QUALITY ASSURANCE/QUALITY CONTROL

A. For each CEMS/COMS a Quality Assurance/Quality Control (QA/QC) plan shall be submitted to the Department (Attn.: Air Division, CEM Coordinator). CEMS quality assurance procedures are defined in 40 CFR, Part 60, Appendix F. This plan shall be submitted within 180 days of the CEMS/COMS installation. A QA/QC plan shall consist of procedure and practices which assures acceptable level of monitor data accuracy, precision, representativeness, and availability.

B. The submitted QA/QC plan for each CEMS/COMS shall not be considered as accepted until the facility receives a written notification of acceptance from the Department.

C. Facilities responsible for one, or more, CEMS/COMS used for compliance monitoring shall meet these minimum requirements and are encouraged to develop and implement a more extensive QA/QC program, or to continue such programs where they already exist. Each QA/QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS/COMS
    a. Daily calibrations (including the approximate time(s) that the daily zero and span drifts will be checked and the time required to perform these checks and return to stable operation)
2. Calibration drift determination and adjustment of CEMS/COMS
    a. Out-of-control period determination
    b. Steps of corrective action
3. Preventive maintenance of CEMS/COMS
    a. CEMS/COMS information
        1) Manufacture
        2) Model number
        3) Serial number
    b. Scheduled activities (check list)
    c. Spare part inventory
4. Data recording, calculations, and reporting
5. Accuracy audit procedures including sampling and analysis methods
6. Program of corrective action for malfunctioning CEMS/COMS

D. A Relative Accuracy Test Audit (RATA), shall be conducted at least once every four calendar quarters. A Relative Accuracy Audit (RAA), or a Cylinder Gas Audit (CGA), may be conducted in the other three quarters but in no more than three quarters in succession. The RATA should be conducted in accordance with the applicable test procedure in 40 CFR Part 60 Appendix A and calculated in accordance with the applicable performance specification in 40 CFR Part 60 Appendix B. CGA's and RAA's should be conducted and the data calculated in accordance with the procedures outlined on 40 CFR Part 60

Appendix E

Appendix F.

If alternative testing procedures or methods of calculation are to be used in the RATA, RAA or CGA audits prior authorization must be obtained from the ADEQ CEM Coordinator.

E. Criteria for excessive audit inaccuracy.

RATA

All Pollutants except Carbon Monoxide	> 20% Relative Accuracy
Carbon Monoxide	> 10% Relative Accuracy
All Pollutants except Carbon Monoxide	> 10% of the Applicable Standard
Carbon Monoxide	> 5% of the Applicable Standard
Diluent (O_2 & CO_2)	> 1.0 % O2 or CO2
Flow	> 20% Relative Accuracy

CGA

Pollutant	> 15% of average audit value or 5 ppm difference
Diluent (O_2 & CO_2)	> 15% of average audit value or 5 ppm difference

RAA

Pollutant	> 15% of the three run average or > 7.5 % of the applicable standard
Diluent (O_2 & CO_2)	> 15% of the three run average or > 7.5 % of the applicable standard

F. If either the zero or span drift results exceed two times the applicable drift specification in 40 CFR, Part 60, Appendix B for five consecutive, daily periods, the CEMS is out-of-control. If either the zero or span drift results exceed four times the applicable drift specification in Appendix B during a calibration drift check, the CEMS is out-of-control. If the CEMS exceeds the audit inaccuracies listed above, the CEMS is out-of-control. If a CEMS is out-of-control, the data from that out-of-control period is not counted towards meeting the minimum data availability as required and described in the applicable subpart. The end of the out-of-control period is the time corresponding to the completion of the successful daily zero or span drift or completion of the successful CGA, RAA or RATA.

G. A back-up monitor may be placed on an emission source to minimize monitor downtime. This back-up CEMS is subject to the same QA/QC procedure and practices as the primary CEMS. The back-up CEMS shall be certified by a PST. Daily zero-span checks must be performed and recorded in accordance with standard practices. When the primary CEMS goes down, the back-up CEMS may then be engaged to sample, analyze and record the emission source pollutant until repairs are made and the primary unit is placed back in service. Records must be maintained on site when the back-up CEMS is placed in service, these records shall include at a minimum the reason the primary CEMS is out of service, the date and time the primary CEMS was out of service and the date and time the primary CEMS was placed back in service.

Appendix F

40 CFR Part 60, Subpart Db – *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*

Appendix F

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Source: 72 FR 32742, June 13, 2007, unless otherwise noted.

§ 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the particulate matter (PM) and nitrogen oxides (NO_X) standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are subject to the PM and NO_Xstandards under this subpart and to the sulfur dioxide (SO_2) standards under subpart D (§60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the NO_Xstandards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are also subject to the NO_Xstandards under this subpart and the PM and SO_2standards under subpart D (§60.42 and §60.43).

(c) Affected facilities that also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; §60.104) are subject to the PM and NO_Xstandards under this subpart and the SO_2standards under subpart J (§60.104).

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; §60.50) are subject to the $NO_X$and PM standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; §60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under §60.281 is not considered a modification under §60.14 and the steam generating unit is not subject to this subpart.

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, the following authorities shall be retained by the Administrator and not transferred to a State.

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, or subpart AAAA of this part is not covered by this subpart.

(i) Heat recovery steam generators that are associated with combined cycle gas turbines and that meet the applicability requirements of subpart GG or KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).

(k) Any affected facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.

Appendix F

§ 60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide (CO_2) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

Chemical manufacturing plants mean industrial plants that are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

Cogeneration , also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Coke oven gas means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

Combined cycle system means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a steam generating unit.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO_2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Gaseous fuel means any fuel that is present as a gas at ISO conditions.

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Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m^3 (70,000 Btu/hr-ft^3).

ISO Conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m^3 (70,000 Btu/hr-ft^3) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

Natural gas means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical SO_2emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Pulp and paper mills means industrial plants that are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2emission control, has a SO_2emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005, *very low sulfur oil* means an oil that contains no more than 0.3 weight percent sulfur or that, when combusted without SO_2emission control, has a SO_2emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a SO_2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

§ 60.42b Standard for sulfur dioxide (SO2).

(a) Except as provided in paragraphs (b), (c), (d), or (k) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction) and the emission limit determined according to the following formula:

$$E_s = \frac{(K_a H_a + K_b H_b)}{(H_a + H_b)}$$

Where:

E_s= SO_2emission limit, in ng/J or lb/MMBtu heat input;

K_a= 520 ng/J (or 1.2 lb/MMBtu);

K_b= 340 ng/J (or 0.80 lb/MMBtu);

H_a= Heat input from the combustion of coal, in J (MMBtu); and

H_b= Heat input from the combustion of oil, in J (MMBtu).

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO_2emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable.

(c) On and after the date on which the performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO_2emissions, shall cause to be discharged into the atmosphere any gases that contain SO_2in excess of 50 percent of the potential SO_2emission rate (50 percent reduction) and that contain SO_2in excess of the emission limit determined according to the following formula:

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$$E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$$

Where:

E_s= SO_2emission limit, in ng/J or lb/MM Btu heat input;

K_c= 260 ng/J (or 0.60 lb/MMBtu);

K_d= 170 ng/J (or 0.40 lb/MMBtu);

H_c= Heat input from the combustion of coal, in J (MMBtu); and

H_d= Heat input from the combustion of oil, in J (MMBtu).

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section.

(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

(2) Affected facilities located in a noncontinental area; or

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section and §60.45b(a), the SO_2emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential SO_2emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential SO_2emissions and

(2) Emissions from the pretreated fuel (without combustion or post-combustion SO_2control) are equal to or less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the SO_2control system is not being operated because of malfunction or maintenance of the SO_2control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in §60.45b(c) or §60.45b(d), and following the monitoring procedures as described in §60.47b(a) or §60.47b(b) to determine SO_2emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in §60.49b(r).

(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

(2) Units firing only very low sulfur oil and/or a mixture of gaseous fuels with a potential SO_2emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2emissions limit in paragraph 60.42b(k)(1).

(3) Units that are located in a noncontinental area and that combust coal or oil shall not discharge any gases that contain SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil.

(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

§ 60.43b Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input, (i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.

(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or SO_2emissions is not subject to the PM limits under §60.43b(a).

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce SO_2emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if (i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood;

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood; and

(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input;

(i) If the affected facility combusts only municipal-type solid waste; or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less;

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less;

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for municipal-type solid waste, or municipal-type solid waste and other fuels; and

(iv) Construction of the affected facility commenced after June 19, 1984, but on or before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

(f) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(g) The PM and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), and (h)(5) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input,

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.3 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in

combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2or PM emissions is not subject to the PM limits under §60.43b(h)(1).

§ 60.44b Standard for nitrogen oxides (NOX).

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X(expressed as NO_2) in excess of the following emission limits:

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO_2) heat input	
	ng/J	lb/MMBTu
(1) Natural gas and distillate oil, except (4):		
(i) Low heat release rate	43	0.10
(ii) High heat release rate	86	0.20
(2) Residual oil:		
(i) Low heat release rate	130	0.30
(ii) High heat release rate	170	0.40
(3) Coal:		
(i) Mass-feed stoker	210	0.50
(ii) Spreader stoker and fluidized bed combustion	260	0.60
(iii) Pulverized coal	300	0.70
(iv) Lignite, except (v)	260	0.60
(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace	340	0.80
(vi) Coal-derived synthetic fuels	210	0.50
(4) Duct burner used in a combined cycle system:		
(i) Natural gas and distillate oil	86	0.20
(ii) Residual oil	170	0.40

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_Xin excess of a limit determined by the use of the following formula:

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$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

E_n= NO_Xemission limit (expressed as NO_2), ng/J (lb/MMBtu);

EL_{go}= Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

H_{go}= Heat input from combustion of natural gas or distillate oil, J (MMBtu);

EL_{ro}= Appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/MMBtu);

H_{ro}= Heat input from combustion of residual oil, J (MMBtu);

EL_c= Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c= Heat input from combustion of coal, J (MMBtu).

(c) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_Xin excess of the emission limit for the coal or oil, or mixtures of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_Xin excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas.

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO_Xin excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

E_n= NO_Xemission limit (expressed as NO_2), ng/J (lb/MMBtu);

EL_{go}= Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

H_{go}= Heat input from combustion of natural gas, distillate oil and gaseous byproduct/waste, J (MMBtu);

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EL_{ro}= Appropriate emission limit from paragraph (a)(2) for combustion of residual oil and/or byproduct/waste, ng/J (lb/MMBtu);

H_{ro}= Heat input from combustion of residual oil, J (MMBtu);

EL_c= Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c= Heat input from combustion of coal, J (MMBtu).

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a NO_xemission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as NO_xemissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific NO_xemission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, by conducting a 30-day performance test as provided in §60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The NO_xemission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific NO_xemission limit will be established at the NO_xemission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing NO_xemissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_xlimit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the NO_xemission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on NO_xemissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the NO_xemission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the NO_xemission limits of this section. The NO_xemission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).) In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_xlimit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(h) For purposes of paragraph (i) of this section, the NO_xstandards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the NO_X emission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X(expressed as NO_2) in excess of the following limits:

(1) If the affected facility combusts coal, oil, or natural gas, or a mixture of these fuels, or with any other fuels: A limit of 86 ng/J (0.20 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:

E_n= NO_X emission limit, (lb/MMBtu);

H_{go}= 30-day heat input from combustion of natural gas or distillate oil; and

H_r= 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of §60.48Da(i) of subpart Da of this part, and must monitor emissions according to §60.49Da(c), (k), through (n) of subpart Da of this part.

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The SO_2 emission standards under §60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil and complying with the fuel based limit under §60.42b(d) or §60.42b(k)(2) are allowed to exceed the limit 30 operating days per calendar year for by-product plant maintenance.

(b) In conducting the performance tests required under §60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential SO_2 emission rate (% P_s) and the SO_2 emission rate (E_s) pursuant to §60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the SO_2 standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) If only coal, only oil, or a mixture of coal and oil is combusted, the following procedures are used:

(i) The procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system (CEMS) of §60.47b (a) or (b).

(ii) The percent of potential SO_2 emission rate (%P_s) emitted to the atmosphere is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

$\%P_s$= Potential SO_2emission rate, percent;

$\%R_g$= SO_2removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$= SO_2removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:

(i) An adjusted hourly SO_2emission rate ($E_{ho}°$) is used in Equation 19–19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate ($E_{ao}°$). The Eho° is computed using the following formula:

$$E_{ho}^{\circ} = \frac{E_{ho} - E_w(1 - X_k)}{X_k}$$

Where:

$E_{ho}°$ = Adjusted hourly SO_2emission rate, ng/J (lb/MMBtu);

E_{ho}= Hourly SO_2emission rate, ng/J (lb/MMBtu);

E_w= SO_2concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value $E_w$for each fuel lot is used for each hourly average during the time that the lot is being combusted; and

X_k= Fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(ii) To compute the percent of potential SO_2emission rate ($\%P_s$), an adjusted $\%R_g$($\%R_g°$) is computed from the adjusted $E_{ao}°$ from paragraph (b)(3)(i) of this section and an adjusted average SO_2inlet rate ($E_{ai}°$) using the following formula:

$$\%R_g^{\circ} = 100\left(1.0 - \frac{E_{ao}^{\circ}}{E_{ai}^{\circ}}\right)$$

To compute $E_{ai}°$, an adjusted hourly SO_2inlet rate ($E_{hi}°$) is used. The $E_{hi}°$ is computed using the following formula:

$$E_{hi}^{\circ} = \frac{E_{hi} - E_w(1 - X_k)}{X_k}$$

Where:

E_{hi}^{o} = Adjusted hourly SO_2 inlet rate, ng/J (lb/MMBtu); and

E_{hi} = Hourly SO_2 inlet rate, ng/J (lb/MMBtu).

(4) The owner or operator of an affected facility subject to paragraph (b)(3) of this section does not have to measure parameters E_w or X_k if the owner or operator elects to assume that X_k = 1.0. Owners or operators of affected facilities who assume X_k = 1.0 shall:

(i) Determine $\%P_s$ following the procedures in paragraph (c)(2) of this section; and

(ii) Sulfur dioxide emissions (E_s) are considered to be in compliance with SO_2 emission limits under §60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of §60.42b(d) does not have to measure parameters E_w or X_k under paragraph (b)(3) of this section if the owner or operator of the affected facility elects to measure SO_2 emission rates of the coal or oil following the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.

(e) The owner or operator of an affected facility subject to §60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under §60.8, compliance with the SO_2 emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for SO_2 for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.

(g) After the initial performance test required under §60.8, compliance with the SO_2 emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for SO_2 for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for SO_2 are calculated to show compliance with the standard.

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraph (c), of this section whether or not the minimum emissions data requirements under §60.46b are achieved. All valid emissions data, including valid SO_2 emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating $\%P_s$ and E_{ho} pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the SO_2 control systems when oil is combusted as provided under §60.42b(i), emission data are not used to calculate $\%P_s$ or E_s under §60.42b(a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under §60.42b(i).

(j) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance under §§60.42b(d)(4), 60.42b(j), and 60.42b(k)(2) shall follow the applicable procedures under §60.49b(r).

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_X emission standards under §60.44b apply at all times.

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(b) Compliance with the PM emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the NO_X emission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

(1) Method 3B of appendix A of this part is used for gas analysis when applying Method 5 or 17 of appendix A of this part.

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (32 °F). The procedures of sections 2.1 and 2.3 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of PM emissions, the oxygen (O_2) or CO_2 sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for NO_X required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring NO_X under §60.48(b).

(1) For the initial compliance test, NO_X from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_X emission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NO_X emission standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NO_X standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(4) Following the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X standards under §60.44b

through the use of a 30-day performance test. During periods when performance tests are not requested, NO_x emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_x emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in §60.49b(e), the requirements of §60.48b(g)(1) apply and the provisions of §60.48b(g)(2) are inapplicable.

(f) To determine compliance with the emissions limits for NO_x required by §60.44b(a)(4) or §60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under §60.8 as follows:

(i) The emissions rate (E) of NO_x shall be computed using Equation 1 in this section:

$$E = E_{sg} + \left(\frac{H_g}{H_b}\right)\left(E_{sg} - E_g\right) \qquad \text{(Eq.1)}$$

Where:

E = Emissions rate of NO_x from the duct burner, ng/J (lb/MMBtu) heat input;

E_{sg}= Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;

H_g= Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);

H_b= Heat input rate to the duct burner, in J/hr (MMBtu/hr); and

E_g= Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.

(ii) Method 7E of appendix A of this part shall be used to determine the NO_x concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O_2 concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under §60.44b(a)(4) or §60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under §60.48b for measuring NO_x and O_2 and meet the requirements of §60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NO_x emissions rate at the outlet from the steam generating unit shall constitute the NO_x emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference, see §60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of §60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of §60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in §60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

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(1) Conduct an initial performance test as required under §60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_xemission standards under §60.44b using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NO_xemission standards under §60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods.

(i) The owner or operator of an affected facility seeking to demonstrate compliance under paragraph §60.43b(h)(5) shall follow the applicable procedures under §60.49b(r).

(j) In place of PM testing with EPA Reference Method 5, 5B, or 17 of appendix A of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 of appendix A of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(13) of this section.

(1) Notify the Administrator one month before starting use of the system.

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (j) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2(or CO_2) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraphs (j)(7)(i) of this section.

(i) For PM, EPA Reference Method 5, 5B, or 17 of appendix A of this part shall be used.

(ii) For O_2(or CO_2), EPA reference Method 3, 3A, or 3B of appendix A of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours per 30-day rolling average.

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§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b), (f), and (h) of this section, the owner or operator of an affected facility subject to the SO_2standards under §60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2concentrations and either O_2or CO_2concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the $SO_2$and either O_2or CO_2concentrations shall both be monitored at the inlet and outlet of the SO_2control device. If the owner or operator has installed and certified $SO_2$and O_2or CO_2CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, SO_2concentration data and CO_2(or O_2) data are collected simultaneously; and

(2) In addition to meeting the applicable $SO_2$and CO_2(or O_2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(3) The reporting requirements of §60.49b are met. $SO_2$and CO_2(or O_2) data used to meet the requirements of §60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2input rate, or

(2) Measuring SO_2according to Method 6B of appendix A of this part at the inlet or outlet to the SO_2control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable $SO_2$and CO_2measurement train operated at the candidate location and a second similar train operated according to the procedures in section 3.2 and the applicable procedures in section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily SO_2emission rate, E_D, shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A–8) and stated in ng/J (lb/MMBtu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/MMBtu) for 30 successive steam generating unit operating days using equation 19–20 of Method 19 of appendix A of this part.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average SO_2emission rates measured by the CEMS required by paragraph (a) of this section and required under §60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under §60.42(b). Each 1-hour average SO_2emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to §60.13(h)(2). Hourly SO_2emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO_2CEMS at the inlet to the SO_2control device is 125 percent of the maximum estimated hourly potential SO_2emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO_2control device is 50 percent of the maximum estimated hourly potential SO_2emissions of the fuel combusted. Alternatively, SO_2span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required $CO_2$and O_2monitors and for $SO_2$and NO_Xmonitors with span values less than 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to $SO_2$and NO_Xspan values less than 100 ppm;

(ii) For all required $CO_2$and O_2monitors and for $SO_2$and NO_Xmonitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for $SO_2$and NO_Xspan values less than or equal to 30 ppm; and

(iii) For SO_2, CO_2, and O_2monitoring systems and for NO_Xemission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2(regardless of the SO_2emission level during the RATA), and for $NO_X$when the average NO_Xemission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under §60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in §60.49b(r).

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a CEMS for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_Xstandard under §60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring $NO_X$and O_2(or CO_2) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NO_Xemission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.49b. Data reported to meet the requirements of §60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(c) The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average NO_Xemission rates measured by the continuous NO_Xmonitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(h)(2).

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a continuous monitoring system for measuring opacity shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for $NO_X$is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NO_Xspan values shall be determined as follows:

Fuel	Span values for NO_X (ppm)

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Natural gas	500.
Oil	500.
Coal	1,000.
Mixtures	500 (x + y) + 1,000z.

Where:

x = Fraction of total heat input derived from natural gas;

y = Fraction of total heat input derived from oil; and

z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NO_xspan values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When NO_xemission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or

(2) Monitor steam generating unit operating conditions and predict NO_xemission rates as specified in a plan submitted pursuant to §60.49b(c).

(h) The owner or operator of a duct burner, as described in §60.41b, that is subject to the NO_xstandards of §60.44b(a)(4) or §60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NO_xemissions.

(i) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) is not required to install or operate a CEMS for measuring NO_xemissions.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), or (5) of this section is not required to install or operate a COMS for measuring opacity if:

(1) The affected facility uses a PM CEMS to monitor PM emissions; or

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO_2emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO_2or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under §60.49b(r); or

(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce SO_2or PM emissions; or

(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(5) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the appropriate delegated permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

(k) Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a CEMS, and record the output of the system, for PM emissions discharged to the atmosphere as specified in §60.46b(j). The CEMS specified in paragraph §60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

§ 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and

(4) Notification that an emerging technology will be used for controlling emissions of SO_2. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2, PM, and/or NO_Xemission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the NO_Xstandard of §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions under the provisions of §60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored under §60.48b(g)(2) and the records to be maintained under §60.49b(j). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

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(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NO_Xemission rates (*i.e.* , ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (*i.e.* , the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.* , flue gas O_2level);

(2) Include the data and information that the owner or operator used to identify the relationship between NO_Xemission rates and these operating conditions; and

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(j).

(d) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §§60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see §60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For facilities subject to the opacity standard under §60.43b, the owner or operator shall maintain records of opacity.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_Xstandards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_Xemission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NO_Xemission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_Xemission rates are in excess of the NO_Xemissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards under §60.43b(e) or to the operating parameter monitoring requirements under §60.13(i)(1).

(2) Any affected facility that is subject to the NO_Xstandard of §60.44b, and that:

(i) Combusts natural gas, distillate oil, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_Xemissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_xemission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_xunder §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO_2standards under §60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO_2emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Each 30-day average percent reduction in SO_2emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO_2or diluent (O_2or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(7) Identification of times when hourly averages have been obtained based on manual sampling methods;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average SO_2emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which $S0_2$or diluent (O_2or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(5) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(6) Identification of times when hourly averages have been obtained based on manual sampling methods;

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO_2standards under §60.42(b) for which the minimum amount of data required under §60.47b(f) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates;

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) If a percent removal efficiency by fuel pretreatment (*i.e.* , $\%R_f$) is used to determine the overall percent reduction (*i.e.* , $\%R_o$) under §60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

(1) Indicating what removal efficiency by fuel pretreatment (*i.e.* , $\%R_f$) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in §60.44b(j), the results of any NO_Xemission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_Xemission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in §60.42b or §60.43b shall either:

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(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) or §60.42b(k)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil as defined in §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition and/or pipeline quality natural gas was combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in §60.42b or §60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific NO_xstandard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions* .

Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_xemission limit for fossil fuel in §60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NO_xemission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring* . (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The NO_xemission limit shall be determined by the compliance and performance test methods and procedures for NO_xin §60.46b(i).

(iii) The monitoring of the NO_xemission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NO_xstandard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions* .

Air ratio control damper is defined as the part of the low NO_xburner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

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(2) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_xemission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_xemission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides* . (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The NO_xemission limit shall be determined by the compliance and performance test methods and procedures for NO_xin §60.46b.

(iii) The monitoring of the NO_xemission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia* . (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low NO_xtechnology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_xemissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for $SO_2$and/or $NO_x$and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific NO_xstandard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_xemission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_xemission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides* . (i) The NO_xemissions shall be determined by the compliance and performance test methods and procedures for NO_xin §60.46b.

(ii) The monitoring of the NO_xemissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements* . (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

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(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(y) Facility-specific NO_xstandard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for NO* $_x$. (i) When fossil fuel alone is combusted, the NO_xemission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NO_xemission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for NO* $_x$. (i) The NO_xemissions shall be determined by the compliance and performance test methods and procedures for NO_xin §60.46b.

(ii) The monitoring of the NO_xemissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements* . (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

CERTIFICATE OF SERVICE

I, Cynthia Hook, hereby certify that a copy of this permit has been mailed by first class mail to American Electric Power Service Corp. - Turk Power Plant, PO Box 660164, Dallas, TX, 75266-0164, on this 5th day of November, 2008.

Cynthia Hook, AAII, Air Division