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VIA ELECTRONIC AND U.S. MAIL

May 25, 2012

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Kathleen Cox
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Re: Petition to Object to Proposed Title V Permit for GenOn REMA, LLC's Shawville Generating Station, ID No. 17-00001

Dear Administrator Jackson and Manager Cox:

Please find enclosed a copy of the Sierra Club's Petition to Object to the Proposed Title V Permit for GenOn REMA, LLC's Shawville Generation Station. Also enclosed is a disc containing the exhibits to the Petition, and a paper copy of Exhibit 6, a modeling report analyzing the sulfur dioxide emissions from Shawville for their impact on ambient air quality. Also included are the modeling files undergirding the report itself.

Copies of the petition and the exhibits thereto have been sent to you via electronic mail.

Please let me know if there is anything further I can provide.

Sincerely,

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BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF THE PROPOSED TITLE V	)	
PERMIT FOR	)	
	)	
GENON REMA, LLC	)	ID NO. 17-00001
	)	
SHAWVILLE GENERATING STATION	)	
PROPOSED TITLE V/STATE OPERATING PERMIT	)	
IN CLEARFIELD COUNTY, PA	)	
	)	
ISSUED BY THE PENNSYLVANIA	)	
DEPARTMENT OF ENVIRONMENTAL PROTECTION	)	
	)	
	)	

PETITION TO OBJECT TO THE PROPOSED TITLE V PERMIT FOR GENON REMA, LLC'S SHAWVILLE GENERATING STATION ISSUED BY THE PENNSYLVANIA DEPARTMENT OF ENVIRONMENTAL PROTECTION

PETITION TO OBJECT TO THE PROPOSED TITLE V PERMIT FOR GENON REMA, LLC'S SHAWVILLE GENERATING STATION

As per Section 505 of the Clean Air Act ("CAA"), the Sierra Club hereby respectfully petitions EPA to object to the proposed Title V permit for GenOn REMA, LLC's Shawville Generating Station in Clearfield County, Pennsylvania ("Shawville"), issued by Pennsylvania Department of Environmental Protection ("PaDEP"). The permit as issued contains provisions that are not in compliance with applicable requirements under the CAA, and accordingly objection by the EPA is proper. 42 U.S.C. § 7661d(b). Specifically, (1) the permit fails to include emission limits and monitoring sufficient to prevent the plant from causing impermissible air pollution in the form of harmful concentrations of sulfur dioxide, and (2) the permit fails to require adequate monitoring to ensure compliance with its particulate matter emission limits.

Accordingly, the EPA should object to the permit's issuance by PaDEP.

INTRODUCTION

A. The Shawville Plant and its Title V Permitting

Shawville is a power plant located in Clearfield County, Pennsylvania, consisting of four coal-filed boilers that came on-line between 1954 and 1960, with a combined nameplate capacity of 597 megawatts, and three diesel-fired units with a collective capacity of six megawatts. The Plant lacks many basic emissions control technologies, such as baghouses, selective catalytic reduction, and, in particular, flue gas desulfurization ("FGD") systems. In 2011, Shawville emitted over 3,500 tons of nitrogen oxides ("NO_x"), more than 25,000 tons of sulfur dioxide ("SO_2"), and nearly 1.8 million tons of carbon dioxide ("CO_2").[1]

GenOn's predecessor submitted an application for a renewal Title V permit for the Shawville plant in April 2005, in advance of that permit's expiration in October 2005. Five years later, in November of 2010, PaDEP issued a draft permit for public notice and comment. *See* Draft Permit, attached hereto as Exhibit 1.

Among other things, the draft permit set emission limits for SO_2 as follows, for each coal-fired boiler:

- Thirty-day running average not to be exceeded at any time: 3.7 lbs./MMBtu
- Daily average not to be exceeded more than 2 days in any running 30-day period: 4.0 lbs./MMBtu
- Daily average not to be exceeded at any time: 4.8 lbs./MMBtu

See Draft Permit at 26, 34, 42, and 50.

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[1] Data taken from U.S. EPA Clean Air Markets Program Data, *available at* http://ampd.epa.gov/ampd/.

On January 4, 2011, the Sierra Club submitted comments on the draft permit. Sierra Club Comments on Shawville Draft Title V Permit (hereinafter "Sierra Club Comments"), attached hereto as Exhibit 2.[2] In its comments, the Sierra Club argued that the draft permit failed to comply with requirements under the CAA and the Pennsylvania State Implementation Plan ("SIP"). In particular, the Sierra Club argued that the draft permit impermissibly failed to ensure that Shawville would not cause air pollution, the prohibition of which is contained in the Pennsylvania SIP and is thus an applicable requirement. The comments used the then-new one-hour SO_2 National Ambient Air Quality Standard ("NAAQS") as a gauge of air pollution. Sierra Club also argued that the permit failed to require monitoring of Shawville's particulate matter emissions sufficient to ensure compliance with the draft permit's proposed limits.[3]

B. The SO_2 NAAQS

Under the CAA, EPA is required to promulgate National Ambient Air Quality Standards ("NAAQS") for SO_2 and other pollutants to protect the public health and welfare. 42 U.S.C. § 7409. As per Section 109 of the CAA, national primary ambient air quality standards are standards requisite to protect the public health, allowing an adequate margin of safety. 42 U.S.C. § 7409(b). On June 3, 2010, EPA issued a new SO_2 NAAQS standard, recognizing that the prior 24-hour and annual SO_2 standards did not adequately protect the public against adverse respiratory effects associated with short term (5 minutes to 24 hours) SO_2 exposure.

The new 2010 SO_2 NAAQS standard is a 1-hour standard set at 196 micrograms per cubic meter (or 75 ppb). 40 C.F.R. § 50.17(a). The new standard was established in the form of the 99th percentile of the annual distribution of the daily maximum 1-hour average concentrations. *Id* at § 50.17(b). Due to both the shorter averaging time and the numerical difference, the new 1-hour SO_2 NAAQS is far more stringent than the prior SO_2 NAAQS. The new NAAQS is projected to have enormous beneficial effects for public health: EPA has estimated that 2,300-5,900 premature deaths and 54,000 asthma attacks a year will be prevented by the new standard. Envtl. Prot. Agency, *Final Regulatory Impact Analysis (RIA) for the SO_2 National Ambient Air Quality Standards (NAAQS) tbl. 5.14* (2010), attached hereto as Exhibit 4. Put another way, levels of SO_2 air pollution above the standard in the NAAQS are expected to cause thousands of premature deaths and tens of thousands of asthma attacks every year.

In the final rule, EPA recognized the "strong source-oriented nature of SO_2 ambient impacts," Final Rule, 75 Fed. Reg. at 35,370, and concluded that the appropriate methodology for purposes of determining compliance, attainment, and nonattainment with the new NAAQS is modeling. *See* Final Rule, 75 Fed. Reg. at 35,551 (describing

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[2] These comments were timely submitted. *See* December 15, 2010 Correspondence from Joyce Epps to Danielle Gagne (granting an extension of the comment period to January 4, 2011 on the grounds that a file review of documents underlying the draft permit were not available until December 16, 2010), attached hereto as Exhibit 3.

[3] The Sierra Club also argued that the draft permit did not provide sufficiently detailed requirements for continuous emissions monitoring of SO_2, carbon dioxide, and NO_x; these concerns were shared by EPA, and were addressed by PaDEP in the proposed permit. *See* Sierra Club Comments at 8-9.

dispersion modeling as "the most technically appropriate, efficient, and readily available method for assessing short-term ambient SO_2 concentrations in areas with large point sources."). Accordingly, in promulgating the new SO_2 NAAQS, EPA explained that, for the 1-hour standard, "it is more appropriate and efficient to principally use modeling to assess compliance for medium to larger sources . . . ." *Id.* at 35,570. As such, EPA has noted that "even if monitoring does not show a violation," that absence of data is not determinative of attainment status absent modeling, and that monitoring in general is "less appropriate, more expensive, and slower to establish." *Id.*; *see also Montana Sulphur & Chemical Co. v. EPA*, 666 F.3d 1174 (9th Cir. 2012) (affirming use of modeling to ascertain SO_2 pollution impacts); U.S. EPA, Final Response to Petition From New Jersey Regarding SO_2 Emissions From the Portland Generating Station, 76 Fed. Reg. 69,052 (Nov. 7, 2011) (using modeling to set emission limits sufficient to prevent air pollution)

On March 24, 2011, EPA released modeling guidance for evaluating compliance with the 1-hour SO_2 NAAQS and designating areas in attainment or nonattainment. *See Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standard* (hereinafter "March 2011 Guidance"), *available at* http://www.epa.gov/ttn/scram/SO2%20Designations%20Guidance%202011.pdf. This March 2011 Guidance specified protocols for performing aerial dispersion modeling appropriate to determine whether a source or sources collectively were causing nonattainment of the 1-hour SO_2 NAAQS. *Id.* Similar to EPA's prior statements in the Final Rule, the March 2011 Guidance affirmed the primacy of modeling in determining whether a source was causing ambient concentrations of SO_2 to exceed the NAAQS. *See id.* at 4.

C. Further Comments from the Sierra Club and the Proposed Permit

On September 22, 2011 the Sierra Club submitted supplemental comments to PaDEP concerning the then still-pending draft permit, providing further detail on the SO_2 air pollution issue raised in the original comments. *See* Supplemental Comments Concerning GenOn Energy, Inc.'s Shawville Generating Station Draft Title V/State Operating Permit (ID No. 17-00001) (hereinafter "Supplemental Comments"), attached hereto as Exhibit 5. Although the Sierra Club had already raised this issue with reasonable specificity during the original public comment period provided by PaDEP, the supplemental comments provided further data to substantiate the issue.

In particular, the supplemental comments enclosed a modeling report prepared by Khanh T. Tran of EMI Environmental, evaluating Shawville's emissions and predicted ambient SO_2 concentrations with respect to the NAAQS. *See* AERMOD Modeling of the SO_2 Impacts of the GenOn Shawville Coal Plant Final Report (hereinafter "Shawville Modeling"), attached hereto as Exhibit 6.[4] This modeling was performed consistent with EPA's published modeling guidance and approach for evaluating impacts from large emitting sources on ambient air quality.

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[4] Also included with the Shawville Modeling are the underlying modeling files themselves, provided on compact disc.

In pertinent part, the Shawville Modeling was based on the facility's permitted SO_2 emissions, in the form of the 4.0 lbs./MMBtu two-day average limit,[5] with the extremely conservative assumption of treating the two-day averaging time limit as if it were an hourly emission limit. *See id.* at 4. These emissions are referred to as the "allowables." *See id.* The modeling indicated that, at the emission levels allowed by the draft permit, Shawville by itself is predicted to cause levels of SO_2 pollution severely above the NAAQS. Shawville is predicted to cause a peak concentration of 2,055.3 $\mu g/m^3$. *Id.* at 6. This is roughly an order of magnitude greater than the NAAQS of 196.2 $\mu g/m^3$. In the residential community of Clearfield, the modeling analysis shows concentrations of between 350 and 500 $\mu g/m^3$—well-above the standard.

Modeled 1-Hour SO_2 Impacts by Allowable Emissions of the GenOn Shawville Plant

Pollutant	Project Conc. (ug/m3)	Background Conc. (ug/m3)	Total Conc. (ug/m3)	NAAQS (ug/m3)	NAAQS Exceed	Percent Over NAAQS
1-hour SO_2 (4th highest)	2,055.3	33	2,088.3	196	**YES**	**965%**

The area of impacts exceeding the 196.2 $\mu g/m^3$ threshold is also quite large. The Shawville Modeling predicts exceedences extending out roughly 30 miles on all sides of the facility. *See id.* at 7. The model additionally predicts that a reduction in allowable emissions of at least 92% would be required to ensure that ambient concentration levels do not exceed the standard. *Id.* at 10. In other words, to avoid causing levels of SO_2 pollution in excess of the health-based standard, the facility would have to have a emission limit at least 92% less than 4.0 lbs./MMBtu on an hourly averaging period; this works out to a limit of 0.32 lbs./MMBtu or less, or 2006 lbs per hour.[6]

Subsequent to the Sierra Club's supplemental comments, PaDEP sent a copy of the proposed permit to EPA on February 13, 2012, and then finalized the permit on March 26, 2012.[7] The proposed permit is largely unchanged from the draft permit, and notably retains the exact same limits for SO_2 emissions as both the draft and the

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[5] These values were taken from the governing, expired Title V permit. *See* Shawville Modeling at 4. The permitted emissions of SO_2 in the draft permit and the proposed permit are exactly the same. *Compare* Draft Permit at 26, 34, 42, and 50 *with* Proposed Permit at 25, 46, 67, and 88.

[6] These limits are calculated in the Shawville Modeling with reference to the heat rating for the Shawville boilers. *See* Shawville Modeling at 4. The Shawville Permit, however, does not contain heat limits; accordingly, to ensure that the facility does not cause harmful air pollution in excess of the standards in the NAAQS, heat limits would have to be added to the SO_2 lbs./MMBtu limits, to cap the total mass of SO_2 emitted, or else set the mass limit of 2006 lbs of SO_2 per hour. Shawville Modeling at 6.

[7] This petition is accordingly timely: the proposed permit was received by EPA on February 13, 2012, making the deadline for petitions to object May 28, 2012. *See* U.S. EPA, Deadlines for Public Petitions to the Administrator for Permit Objections at 3, attached hereto as Exhibit 7, *available at* http://www.epa.gov/reg3artd/permitting/petitions3.htm; 42 U.S.C. § 7661d(b).

preceding permit that expired in October of 2005. *See generally* Proposed Permit, attached hereto as Exhibit 8.

OBJECTIONS

All Title V sources "shall have a permit to operate that assures compliance by the source with all applicable requirements." 40 C.F.R. § 70.1; *see also* 42 U.S.C. § 7661c(a) ("Each permit issued under this subchapter shall include enforceable emission limitations and standards . . . and such other conditions as are necessary to assure compliance with applicable requirements of this chapter, including the requirements of the applicable implementation plan"). Within 45 days of receipt of a proposed Title V permit, the Administrator of the EPA "shall . . . object" to the permit's issuance if it "contains provisions that are determined by the Administrator as not in compliance with the applicable requirements" of the CAA and "the requirements of an applicable implementation plan." 42 U.S.C. § 7661d(b)(1). If the EPA does not object during this period, any person may petition the Administrator for issuance of an objection. *Id.* at § 7661d(b)(2).

The Sierra Club now petitions EPA to object to the Shawville permit on two separate grounds. First, the permit fails to include limits sufficient to prevent the plant from causing impermissible air pollution in the form of harmful concentrations of sulfur dioxide. *See* Sierra Club Comments at 8; Supplemental Comments at 9. Second, the permit improperly fails to require adequate monitoring to ensure compliance with its particulate matter emission limits.[8]

A. The Permit Improperly Fails to Include SO_2 Emission Limits Sufficient to Prevent Harmful Air Pollution

The Shawville Title V permit fails to include limits on SO_2 emissions sufficient to prevent the facility from causing ambient concentrations in excess of the health-based standard in the 1-hour SO_2 NAAQS, and thereby impermissibly permits air pollution.

1. *Pennsylvania's Prohibition of Harmful Air Pollution is an Applicable Requirement*

Both federal regulations and Pennsylvania state regulations incorporated into Pennsylvania's SIP require that any Title V permit issued contain limits sufficient to meet all "applicable requirements at the time of permit issuance." 40 C.F.R. § 70.6(a)(1); *accord* 25 Pa. Code § 127.512. The term "all applicable requirements" is defined by both the federal regulations and Pennsylvania's regulations to include standards or requirements in the SIP. *See* 40 C.F.R. § 70.2(1) (defining "applicable requirements" to mean "[a]ny standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA"); 25 Pa. Code § 121.1 (defining "applicable

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[8] All grounds for objection were timely raised in the comments submitted by the Sierra Club on the draft Shawville permit. 42 U.S.C. § 7661d(b)(2).

requirements" to mean "standard[s] provided for in the Commonwealth's SIP approved by the EPA").

Pertinently, the federally-approved Pennsylvania SIP contains a requirement that "**[n]o person shall** cause, suffer, or **permit air pollution**" in Pennsylvania. 25 Pa. Code §121.7 (emphasis added). Pennsylvania regulations—again, incorporated into the federally approved SIP—define "air pollution" as follows:

> Air pollution—The presence in the outdoor atmosphere of **any form of contaminant**, including, but not limited to, the discharging from stacks, chimneys, openings, buildings, structures, open fires, vehicles, processes or any other source of any smoke, soot, fly ash, dust, cinders, dirt, noxious or obnoxious acids, fumes, oxides, gases, vapors, odors, toxic, hazardous or radioactive substances, waste or other matter in a place, manner or **concentration inimical or which may be inimical to public health, safety or welfare or which is or may be injurious to human**, plant or animal **life** or to property or which unreasonably interferes with the comfortable enjoyment of life or property.

25 Pa. Code § 121.1 (emphasis added).[9]

EPA has recently affirmed that where prohibitions on air pollution are part of a SIP, they are enforceable requirements. *See* Letter from Genevieve Damico, Chief, Air Permits Section EPA Region 5 to Michael Ahern, Manager, Permit Issuance, Ohio EPA (Apr. 25, 2012), attached hereto as Exhibit 9. EPA wrote that "if nuisance provisions apply to a stationary source either because it is subject to the provisions in the [state] SIP or because a permit issued pursuant to a SIP-approved program contains the requirements, **the terms must be included in the federally enforceable side of the source's Title V permit**." *Id.* at 1 (emphasis added).[10] Accordingly, the prohibition on harmful air pollution in 25 Pa. Code §§ 121.7 and 121.1 is an applicable requirement that must be incorporated into any Title V permit issued for Shawville.

2. *Causing Exceedences of the 1-Hour SO_2 NAAQS Constitutes Prohibited Harmful Air Pollution*

Further, it is well-established in Pennsylvania that this prohibition on air pollution is enforceable independently—i.e., it is not simply a statement of policy whose implementation is left to other aspects of the SIP. Indeed, no violation of a particular quantitative standard is needed to support a claim for its violation if citizens testify that they are experiencing a nuisance. *See, e.g., Rushton Mining Co. v. Commonwealth*, 328 A.2d 185, 193 (Cmwlth Ct. 1974). A showing of an exceedence of a health-based

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[9] EPA approved these portions of Pennsylvania's SIP, without specific comment, decades ago. 37 Fed. Reg. 10,842, 10,889 (May 31, 1972). They are still part of the SIP today. *See* 40 C.F.R. §52.2020(c)(1) (listing the "Prohibition of Air Pollution" provision as "EPA-approved").

[10] Region 5 has also at least once issued a notice of violation under Illinois's nuisance provision, *see* NOV for H. Kramer & Co. (Apr. 20, 2011), attached hereto as Exhibit 10, informing a polluter that it had violated the provision because its emissions caused violations of a NAAQS standard.

NAAQS standard is an even stronger demonstration of air pollution. The NAAQS are based upon years of research and extensive notice and comment and represent a definitive pollution level above which public health impacts will occur: if a source causes NAAQS violations, it is clearly "inimical to public health [and] safety."

The Pennsylvania Environmental Hearing Board affirmed this in *Commonwealth v. Medusa Corp.*, 1978 EHB 149, 1978 WL 3835 (Pa. Env. Hearing Bd. 1978), *remanded in part on other grounds sub nom. Medusa Corp. v. Commonwealth*, 415 A. 2d 105 (Cmwlth Ct. 1980). That case concerned particulate matter emissions from a cement kiln. The Board affirmed that the pollution prohibition is a substantive requirement, holding that "[t]here can no longer be any doubt that at least in Pennsylvania, causing air pollution itself is a separate offense from the violation of any other specific environmental law or regulation." 1978 WL 3835 at *13. Further, in *Medusa* Pennsylvania carried its case because it could show that the kiln was causing violations of the particulate matter NAAQS: this data, combined with citizen testimony, was "substantial evidence" that Medusa had violated the air pollution prohibition of 25 Penn. Admin Code § 121.7. *Id.*

Accordingly, the specific limit in the 1-hour SO_2 NAAQS of 196.2 micrograms per cubic meter is dispositive *authority* that such levels of SO_2 pollution are "inimical to public health" or "injurious" to human life: the NAAQS and EPA's conclusions regarding the impact of SO_2 pollution demonstrate what constitutes air pollution. As such, the limits in the NAAQS provide a numerical translation of the SIP's prohibition on air pollution.

3. *The CAA Mandates that Title V Permits Incorporate Terms Sufficient to Ensure Compliance with Applicable Requirements*

The CAA provides that "[e]ach permit . . . shall include enforceable emission limitations and standards . . . and such other conditions as are necessary to assure compliance" with all applicable requirements. 42 U.S.C. § 7661c(a). Indeed, EPA may not even approve a Title V program unless it is persuaded that the permitting authority will "assure that upon issuance or renewal permits incorporate emissions limitations and other requirements in an applicable implementation plan." 42 U.S.C. § 7661a(b)(5)(C).

The Title V implementing regulations likewise require each applicant to submit application information sufficient "to determine the applicability of, or to impose, any applicable requirement," 40 C.F.R. § 70.5(c), and to include a "[d]escription of or reference to any applicable test method for determining compliance with each applicable requirement," *id.* at § 70.5(c)(5). The permit itself must, then, contain all "those operational requirements and limitations that assure compliance with all applicable requirements at the time of permit issuance." *Id.* at § 70.6(a)(1).

Importantly, in addition to this substantive obligation to convert general requirements to specific terms, permits must also provide for sufficient monitoring. These monitoring restrictions consist of both "periodic" and "umbrella" monitoring rules. *See generally Sierra Club v. EPA*, 536 F.3d 673 (D.C. Cir. 2011) (discussing these rules). The periodic monitoring rule provides that where an applicable requirement does not, itself, "require periodic testing or instrumental or noninstrumental monitoring," the permit-writer must develop terms directing "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." 40 C.F.R. § 70.6(a)(3)(B). In other words, if NAAQS compliance is a condition of the permit, the permit must contain monitoring of a frequency and type sufficient to ensure compliance.

The "umbrella" monitoring rule, 40 C.F.R. § 70.6(a)(3)(C) backstops this requirement by making clear that permit writers must also correct "a periodic monitoring requirement inadequate to the task of assuring compliance," *Sierra Club*, 536 F.3d at 675. This "gap-filler" makes doubly clear that adequate monitoring is required. *Id.* at 680.

EPA has since affirmed, in a post-*Sierra Club* Title V petition ruling, that these requirements are quite rigorous, making clear that permit writers must develop and "supplement monitoring to assure . . . compliance" on the basis of an extensive record. *In re United States Steep Corp.*, Petition No. V-2009-03, 2011 WL 353368 (EPA Admin. Jan. 31, 2011). ("The rationale for the monitoring requirements must be clear and documented in the permit record," and adequate monitoring is determined by careful, content-specific inquiry into the nature and variability of the emissions at issue).

Relevant Pennsylvania regulations are in accord: applications must include all relevant compliance information, 25 Penn. Admin. Code § 127.503(3), periodic monitoring "sufficient to yield accurate and reliable data from the relevant time that are representative of a source's compliance with the permit," 25 Penn. Admin. Code § 127.511(a)(2), and that the permit, as a whole, must contain "compliance certification, testing, monitoring, reporting and recordkeeping requirements sufficient to assure compliance with the terms and conditions of the permit." 25 Penn. Admin. Code § 127.513(1).

Thus, where there exists analysis sufficient to determine monitoring requirements and emission limits protective of a NAAQS as a numerical translation of the prohibition on air pollution, those limits must be incorporated in Title V permitting in Pennsylvania.

4. *The Shawville Permit Improperly Fails to Ensure Prohibition of Harmful Air Pollution*

Nonetheless, the Shawille Title V permit fails to include limits on SO_2 emissions sufficient to avoid causing nonattainment of the 1-hour SO_2 NAAQS and accordingly prevent prohibited air pollution.[11] Instead, the permit contains the exact same

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[11] PaDEP indeed disclaims any responsibility to include such limits, writing in response to the Sierra Club's comments that:

exceedingly lax emission limits for SO_2 as in the draft permit: a 4.0 lbs./MMBtu two-day average limit. *Compare* Draft Permit at 26, 34, 42, and 50 *with* Proposed Permit at 25, 46, 67, and 88. As noted above, the Sierra Club analyzed this limit with the AERMOD aerial dispersion modeling system specified by EPA, in strict accordance with EPA guidance, to determine whether the limit would be protective of the 1-hour SO_2 NAAQS, and found that the limit would allow for ten-fold exceedences of the standard: peak concentrations of 2,055.3 $\mu g/m^3$, as compared with the standard of 196.2 $\mu g/m^3$. *See* Shawville Modeling at 6.

Although the SIP explicitly prohibits pollution, and although SO_2 levels above the NAAQS are plainly "air pollution" for the purposes of the SIP, the permit does not provide a path to compliance with this requirement, or even require monitoring to assure compliance.[12] As a result, it countenances a continuing violation of the SIP and fails to meet Title V standards. EPA must object to the permit, and require a total SO_2 emission limit of at most 2006 lbs per hour, with continuous monitoring and reporting of emissions. *See* Shawville Modeling at 6.

B. The Shawville Permit Fails to Require Adequate Monitoring to Ensure Compliance with Particulate Matter Emission Limits

The Shawville Title V permit fails in to require monitoring of particulate matter emissions adequate to ensure compliance with applicable limits; instead, the permit requires that particulate matter emissions be tested only once every two years. Because the once-every-two years stack test the Shawville permit contemplates is wholly inadequate to ensure that the continuous particulate matter ("PM") emission limits for the plant are met, the permit must be revised with more stringent monitoring requirements. Here, that would be a PM continuous emissions monitor ("CEMS").[13]

> Nowhere in the definition of "applicable requirement" or in the regulations outlining what must be in the Title V permit, is there a suggestion that a Title V permit must include provisions that would preclude the plant from causing or contributing to a violation of the NAAQS. Until there is an underlying applicable requirement expressly addressing the NAAQS, such as a SIP provision or a federal standard, there is no applicable requirement to preclude the Title V facility from causing ambient air quality exceedances.

PaDEP Response to Comments at 6 (Mar. 26, 2012), attached hereto as Exhibit 11. PaDEP thus effectively concedes that the Shawville permit does not prevent air pollution inimical to human health in the form of violations of the 1-hour SO2 NAAQS. Of course, as explained above, PaDEP's response to comment is moreover simply wrong. The Pennsylvania SIP's prohibition of harmful air pollution constitutes an applicable requirement, and the permit fails to contain emission limits and monitoring sufficient to prevent harmful air pollution in the form of ambient concentrations of SO_2 at levels harmful to human health.

[12] This is despite the fact that the permit specifically includes the prohibition on harmful air pollution among its terms (Permit at 23), and additionally states that "the permittee shall not emit sulfur dioxide in a way that would exceed applicable emission rates and standards, including ambient air quality standards." Permit at 26, 47, 67, 88.

[13] In its responses to Sierra Club's comments, PaDEP argued that continuous emissions standards, such as the PM emission limits here, do not require that "*emissions* be monitored continuously," and that the stack testing in the permit combined with opacity monitoring is sufficient to assure compliance with PM emission limits. PaDEP Response to Comments at 3-4 (emphasis in original). As indicated in this section,

As noted above, he CAA requires that permits "shall set forth . . . monitoring . . . requirements sufficient to assure compliance" with emissions limits in a Title V permit. 42 U.S.C. § 7661c(c). EPA has promulgated regulations in Part 70 that describe the steps permitting authorities must take to fulfill the monitoring requirement from section 504(c). *See* 40 C.F.R. §§ 70.6(a)(3)(i)(A), 70.6(a)(3)(i)(B), and 70.6(c)(1) (2011). The D.C. Circuit in *Sierra Club v. EPA* described the Part 70 rules as requiring three steps to establish periodic monitoring requirements in each Title V permit issued:

> (1) where monitoring requirements already contained in existing regulations or permits, the permitting authority must incorporate those requirements into the permit;
>
> (2) where no previously established monitoring requirements exists for an emission limit, the permitting authority must add "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit;" and
>
> (3) where monitoring requirements exists that correspond to an emission limit, but that monitoring is not sufficient to assure compliance with the permit limit, the permit writer must remedy that deficiency by supplementing inadequate monitoring to make the requirement sufficient to assure compliance.

See Sierra Club v. EPA, 536 F.3d 673, 675 (D.C. Cir. 2008); *see also In re United States Steel Corporation – Granite City Works*, Petition No. V-2009-03, Order Responding to Petitioner's Request that the Administrator Object to Issuance of State Operating Permit, at 6-7 (hereinafter "*U.S. Steel*"), attached hereto as Exhibit 12.

The *Sierra Club* court reiterated the necessity to supplement monitoring requirements: "[w]e read Title V to mean that someone must fix these inadequate monitoring requirements." 536 F.3d at 678.

In addition to setting forth adequate monitoring requirements for emission limits, the permitting authority is required to set forth its rationale in a statement of basis describing why the chosen monitoring regime is adequate to assure compliance with the emissions limit. 40 C.F.R § 70.7(a)(5); *U.S. Steel* at 7. The determination of what monitoring is adequate is a context-specific exercise. *U.S. Steel* at 7. EPA has described the permit writer's monitoring analysis as *beginning* by "assessing whether the monitoring required in the applicable requirement is sufficient to assure compliance with the permit terms and conditions." *Id.* Appropriate factors for the permit writer to consider include: (1) variability of emissions from the unit in question; (2) likelihood of violation of the requirements; (3) whether add-on controls are being used for the unit to

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this response is incorrect—it fails to comport with *Sierra Club v. EPA*, and does nothing to address the variability in PM emissions from coal combustion.

meet the emission limit; (4) the type of monitoring, process, maintenance, or control equipment data already available for the emission unit; and (5) the type and frequency of the monitoring requirements for similar emission units at other facilities. *Id.* Applying these factors, EPA found that stack testing for particulate matter emissions once every five years was insufficient to assure compliance. *Id.* at 31. Similarly, the *Sierra Club* court indicated that frequency of emissions monitoring must reflect the averaging time used to determine compliance. *Sierra Club*, 536 F.3d at 765 (a yearly monitoring requirement would not likely adequately address a daily maximum emission limit); *see also* U.S. EPA, Objection to Proposed Title V Operating Permit for TriGen-Colorado Energy Corporation (Sept. 13, 2000) ("a one-time test does not satisfy the periodic monitoring requirements" under the CAA for PM), attached hereto as Exhibit 13.

Here, the PM emission standard for the Shawville Generating Station's four main boilers is derived from 25 Pa. Code § 123.11(a)(3), and prohibits the emission of "particulate matter from the exhaust of [the source] in excess of 0.1 pound per million Btu of heat input for all four boilers." Permit at 25, 46, 67, 88. The Pennsylvania SIP does not contain provisions requiring specific types of PM monitoring; accordingly, the second scenario described in *Sierra Club* applies: PaDEP is required to include in Title V permits "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." 536 F.3d at 675.

However, the monitoring frequency required by the Shawville permit is not adequate to assure compliance with the hourly limits. The permit provides that stack testing for PM should occur after each "approximate 2-year period," which can be up to "26 months." Permit at 28. Yet it does not provide any explanation for why monitoring once every couple of years is adequate to assure compliance with a continous standard. Nor could it: as EPA has found, such infrequent monitoring is unlawful. *See U.S. Steel* at 7. Instead, PM CEMS are required, as an application of the five *U.S. Steel* factors makes clear.

First, looking at factors one and three together, the variability of emissions, especially as they relate to the add-on controls used by the plant in this case, strongly indicate the necessity for continuous monitoring. Shawville employs electrostatic precipitators ("ESPs") as the means of controlling particulate matter emissions. Permit at 38, 59, 80, 101. As fully described in the attached Declaration of Dr. Ranajit Sahu, this control method, combined with the inherent variability of PM emissions from coal fired boilers, creates a very high degree of variability of in Shawville's PM emissions. *See* Declaration of Ranajit (Ron) Sahu (hereinafter "Sahu Declaration"), attached hereto as Exhibit 14. Specifically, Dr. Sahu notes that various "properties of the fuel (coal), properties of the flyash particles themselves, and factors affecting ESP performance . . . [collectively and through their interactions and variations over time] will affect how much [particulate matter] is actually emitted." *Id.* at 5. Dr. Sahu further notes that "[g]iven these numerous factors [related to the fuel, flyash and ESP], that can singly and in combination, affect the emissions of these pollutants from each of the Shawville boilers, the emissions of PM/PM10/PM2.5 will likely be variable, and significantly so."

Id. at 9. Dr. Sahu goes on to state that it is "not uncommon for such variability to be multiple-times or even an *order of magnitude* different between the typical three back-to-back hourly test runs in a stack test." *Id.* (emphasis added). Dr. Sahu concludes that "it is highly unlikely that an occasional measurement (such as a stack test) will accurately be able to capture such variability . . . [t]hus, continuous measurements of filterable PM, using CEMS that are now available, are the proper means of accurately measuring such emissions." *Id.* at 9-10.

In addition, and as EPA is well aware, stack tests are scheduled well ahead of time. Sources equipped with ESPs like Shawville can and almost always do perform work on their ESPs before the stack test. This includes realigning plates, replacing broken wires and electronics in the ESP as well as cleaning the ESP, all of which improves ESP performance. In fact, sources often have stack testing companies perform "diagnostic tests" before the "official stack test." If the results of the diagnostic test show violations, then the source can simply perform work on the ESP to ensure that it "passes" the official stack test. Thus, the stack test does not tell the public or regulatory agencies whether the source will be in compliance during the following multi-year period when the ESP once again suffers damage and degradation.

Closely related to variability, looking at the second factor—the likelihood of violation—the Shawville facility's history of major violations again mitigates in favor of PM CEMS.[14] Given this past history and the variability of the PM emissions discussed above, continued violation is likely. To assure compliance where the emissions are so variable and the facility has a history of noncompliance, continuous direct monitoring is the only adequate monitoring option.

Finally and perhaps most significantly, under the remaining two factors, the availability and reliability of PM CEMS for similar emission units shows that continuous monitoring will assure compliance with the PM emission limit. PM CEMS are increasingly employed for similar emission units at other facilities comparable to Shawville. These include, for example, the Tampa Electric power plant (Florida),[15] Eli Lilly Corporation (Indiana), and the U.S. Department of Energy (Tennessee), all of which employ PM CEMS.[16] The EPA has also secured commitments from up to 30 existing coal-fired utility installations to install PM CEMS within the next few years. *See* Comment Letter Regarding Robinson Power Company Waste-Coal-Fired Power Generation Facility from David Campbell, Chief Permits and Technical Assessments Branch, United States Environmental Protection Agency Region III to Thomas Joseph, Pennsylvania Department of Environmental Protection at 6 (March 11, 2005), attached hereto as Exhibit 15. For example, American Electric Power Company and SWEPCO have agreed to install PM CEMS at an existing coal-fired power plant. *See* American

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[14] *See* eFacts, Pennsylvania's Environmental Facility Application Compliance Tracking System, *at* http://www.ahs2.dep.state.pa.us/eFACTSWeb/searchResults_singleSite.aspx?SiteID=244416 (last checked May 25, 2012).

[15] *See* Tampa Electric Company Consent Decree at 20-21, attached hereto as Exhibit 16.

[16] *See* United States Environmental Protection Agency, Current Knowledge of Particulate Matter (PM) Continuous Emission Monitoring, EPA-454/R-00-039, (September 2000), at viii and 4-2 to 4-5, attached hereto as Exhibit 17.

Electric Power Company, Inc. and Southwestern Power Company ("SWEPCO") Consent Decree at 5-7, attached hereto as Exhibit 18. PM CEMS have even been required for emitters in Pennsylvania. *See, e.g.*, Citizens for Pennsylvania's Future Consent Decree at 4 (requiring PM CEMS for the Bruce Mansfield plant), attached hereto as Exhibit 19; *see also* DEP Consent Order and Agreement regarding the same at 7-8, attached hereto as Exhibit 20. Given the use, reliability, and accuracy of monitoring requirements for similar emission units at other facilities, EPA should object to the permit and require the use of PM CEMS at Shawville.

CONCLUSION

For the reasons described above, the Sierra Club respectfully requests that the Administrator of the United States Environmental Protection Agency grant this Petition to Object to the Shawville Title V Permit and order the Pennsylvania Department of Environmental Protection to include in a new permit hourly SO_2 emission limits sufficiently stringent to protect the SO_2 NAAQS and thereby avoid causing harmful air pollution, and to require continuous particulate matter emissions monitoring to ensure compliance with particulate matter emission limits.

Respectfully submitted,

Zachary M. Fabish
The Sierra Club
50 F Street NW, 8th Floor
Washington, DC 20001
(202) 675-7917
zachary.fabish@sierraclub.org

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR QUALITY PROGRAM

TITLE V/STATE OPERATING PERMIT

Issue Date:

Effective Date:

Expiration Date:

In accordance with the provisions of the Air Pollution Control Act, the Act of January 8, 1960, P.L. 2119, as amended, and 25 Pa. Code Chapter 127, the Owner, [and Operator if noted] (hereinafter referred to as permittee) identified below is authorized by the Department of Environmental Protection (Department) to operate the air emission source(s) more fully described in this permit. This Facility is subject to all terms and conditions specified in this permit. Nothing in this permit relieves the permittee from its obligations to comply with all applicable Federal, State and Local laws and regulations.

The regulatory or statutory authority for each permit condition is set forth in brackets. All terms and conditions in this permit are federally enforceable applicable requirements unless otherwise designated as "State-Only" or "non-applicable" requirements.

TITLE V Permit No: 17-00001

Federal Tax Id - Plant Code: 52-2154847-3

Owner Information

Name: RRI ENERGY MID ATLANTIC POWER HOLDINGS LLC
Mailing Address: 121 CHAMPION WAY STE 200
CANONSBURG, PA 15317-5817

Plant Information

Plant: RRI ENERGY MID ATLANTIC/SHAWVILLE GENERATING STA
Location: 17 Clearfield County 17909 Bradford Township
SIC Code: 4911 Trans. & Utilities - Electric Services

Responsible Official

Name: MATT E GREEK
Title: VICE PRESIDENT
Phone: (832) 357 - 7560

Permit Contact Person

Name: TIMOTHY E MCKENZIE
Title: SR ENV SCIENTIST
Phone: (724) 597 - 8670

[Signature] ______________________________________
MUHAMMAD Q. ZAMAN, ENVIRONMENTAL PROGRAM MANAGER, NORTHCENTRAL REGION

SECTION A. Table of Contents

SECTION A. Table of Contents

Note: These same sub-sections are repeated for each source!

SECTION A. Site Inventory List

Source ID	Source Name	Capacity/Throughput	Fuel/Material
031	UTILITY BOILER - UNIT 1	1,345.000 MMBTU/HR	
032	UTILITY BOILER - UNIT 2	1,345.000 MMBTU/HR	
033	UTILITY BOILER - UNIT 3	1,790.000 MMBTU/HR	
034	UTILITY BOILER - UNIT 4	1,790.000 MMBTU/HR	
038	15 SPACE HEATERS		
CAIR	CAIR CONDITIONS		
F01	PLANT HAUL ROADS		
F02	COAL HANDLING AND STORAGE		
F03	ASH DISPOSAL FACILITY		
P101	STARTUP GENERATOR 5		
P102	STARTUP GENERATOR 6		
P103	STARTUP GENERATOR 7		
P104	EMERGENCY GENERATOR 1(UNIT 1-2)		
P106	2 FIRE PUMP ENGINES		
P116	WATER TREATMENT OPERATIONS		
P120	EMERGENCY DIESEL GENERATOR		
P121	PARTS WASHERS		
C01	RESEARCH COTTRELL ESP-UNIT 1		
C03	NH3/SO3 INJECTION FLUE GAS-UNIT 1		
C04	RESEARCH COTTRELL ESP-UNIT 2		
C06	NH3/SO3 INJECTION FLUE GAS-UNIT 2		
C08	RESEARCH COTTRELL ESP-UNIT 3		
C09	BUELL ESP-UNIT 1		
C11	RESEARCH COTTRELL ESP-UNIT 4		
C12	BUELL ESP-UNIT 2		
C13A	OVERFIRE AIR-UNIT 3		
C13B	OVERFIRE AIR-UNIT 4		
C14	LOW NOX BURNERS-UNIT 1		
C15	LOW NOX BURNERS-UNIT 2		
C16	LOW NOX BURNER-UNIT 3		
C17	LOW NOX BURNERS-UNIT 4		
C18	BUELL ESP-UNIT 3		
C19	BUELL ESP-UNIT 4		
C20	SNCR 1		
C21	SNCR 2		
C22	SNCR 3		
C23	SNCR 4		
FM01	COAL/SYNFUEL STOCKPLE		
FM02	OIL STORAGE TANKS		
FM03	DIESEL STORAGE		

SECTION A. Site Inventory List

Source ID	Source Name	Capacity/Throughput	Fuel/Material
S01	UNITS 1 & 2 STACK		
S02	UNITS 3 & 4 STACK		
S03	GENERATOR 5 STACK		
S06	EMERGENCY GEN 1 STACK		
S120	GENERATOR STACK		
S13	GENERATOR 6 STACK		
S23	GENERATOR 7 STACK		
SO8	FIRE PUMP ENGINE STACK		
Z01	HAUL ROAD EMISSIONS		
Z02	COAL HANDLING EMISSIONS		
Z03	ASH DISPOSAL EMISSIONS		
Z038	FUGITIVE EMISSIONS		
Z116	WATERTREATMENT EMISSIONS		
Z121	PARTS WASHER EMISSIONS		

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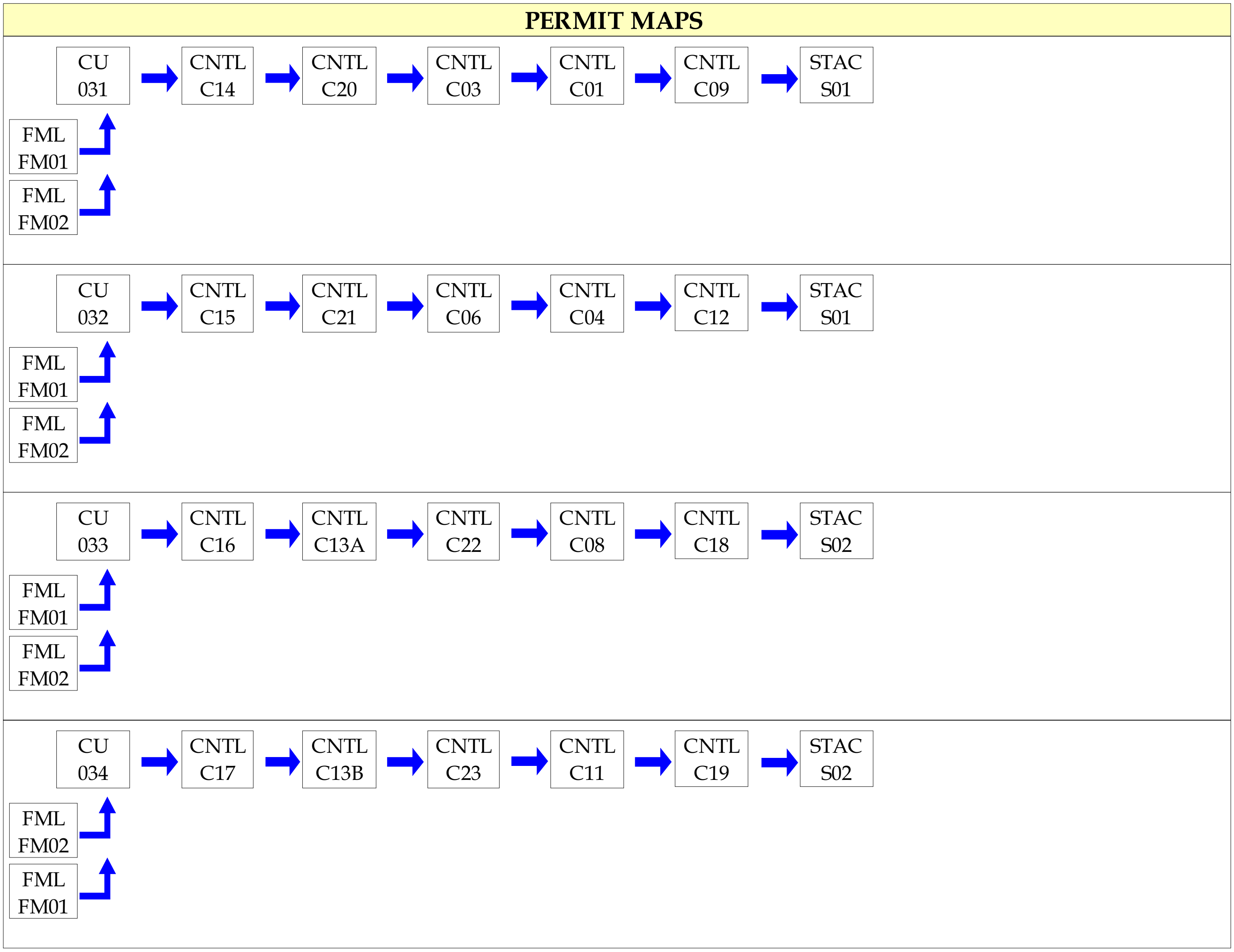
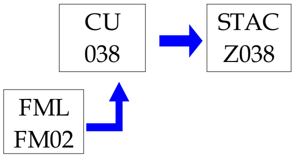


PERMIT MAPS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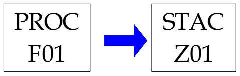
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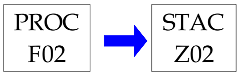
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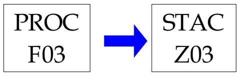
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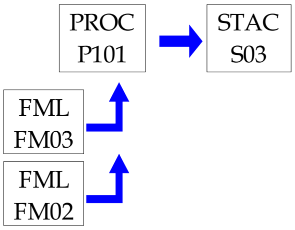
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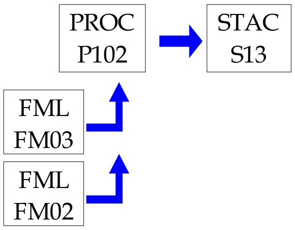
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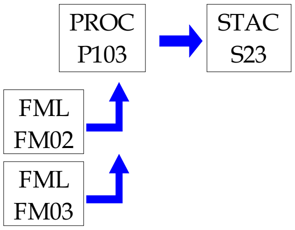
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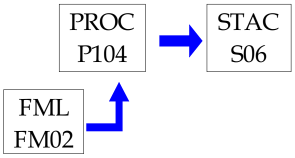
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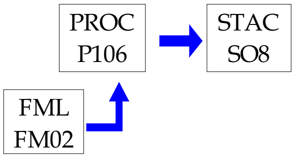
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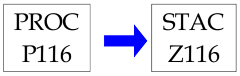
PERMIT MAPS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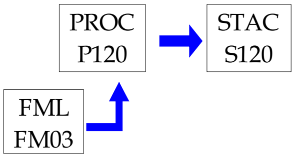
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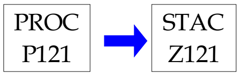
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SECTION B. General Title V Requirements

#001 [25 Pa. Code § 121.1]

Definitions

Words and terms that are not otherwise defined in this permit shall have the meanings set forth in Section 3 of the Air Pollution Control Act (35 P.S. § 4003) and 25 Pa. Code § 121.1.

#002 [25 Pa. Code § 127.512(c)(4)]

Property Rights

This permit does not convey property rights of any sort, or any exclusive privileges.

#003 [25 Pa. Code § 127.446(a) and (c)]

Permit Expiration

This operating permit is issued for a fixed term of five (5) years and shall expire on the date specified on Page 1 of this permit. The terms and conditions of the expired permit shall automatically continue pending issuance of a new Title V permit, provided the permittee has submitted a timely and complete application and paid applicable fees required under 25 Pa. Code Chapter 127, Subchapter I and the Department is unable, through no fault of the permittee, to issue or deny a new permit before the expiration of the previous permit. An application is complete if it contains sufficient information to begin processing the application, has the applicable sections completed and has been signed by a responsible official.

#004 [25 Pa. Code §§ 127.412, 127.413, 127.414, 127.446(e) & 127.503]

Permit Renewal

(a) An application for the renewal of the Title V permit shall be submitted to the Department at least six (6) months, and not more than 18 months, before the expiration date of this permit. The renewal application is timely if a complete application is submitted to the Department's Regional Air Manager within the timeframe specified in this permit condition.

(b) The application for permit renewal shall include the current permit number, the appropriate permit renewal fee, a description of any permit revisions and off-permit changes that occurred during the permit term, and any applicable requirements that were promulgated and not incorporated into the permit during the permit term.

(c) The renewal application shall also include submission of proof that the local municipality and county, in which the facility is located, have been notified in accordance with 25 Pa. Code § 127.413. The application for renewal of the Title V permit shall also include submission of compliance review forms which have been used by the permittee to update information submitted in accordance with either 25 Pa. Code § 127.412(b) or § 127.412(j).

(d) The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall submit such supplementary facts or corrected information during the permit renewal process. The permittee shall also provide additional information as necessary to address any requirements that become applicable to the source after the date a complete renewal application was submitted but prior to release of a draft permit.

#005 [25 Pa. Code §§ 127.450(a)(4) & 127.464(a)]

Transfer of Ownership or Operational Control

(a) In accordance with 25 Pa. Code § 127.450(a)(4), a change in ownership or operational control of the source shall be treated as an administrative amendment if:

(1) The Department determines that no other change in the permit is necessary;

(2) A written agreement has been submitted to the Department identifying the specific date of the transfer of permit responsibility, coverage and liability between the current and the new permittee; and,

(3) A compliance review form has been submitted to the Department and the permit transfer has been approved by the Department.

(b) In accordance with 25 Pa. Code § 127.464(a), this permit may not be transferred to another person except in cases of transfer-of-ownership which are documented and approved to the satisfaction of the Department.

#006 [25 Pa. Code § 127.513, 35 P.S. § 4008 and § 114 of the CAA]

Inspection and Entry

(a) Upon presentation of credentials and other documents as may be required by law for inspection and entry purposes, the permittee shall allow the Department of Environmental Protection or authorized representatives of the Department to perform the following:

(1) Enter at reasonable times upon the permittee's premises where a Title V source is located or emissions related activity is conducted, or where records are kept under the conditions of this permit;

(2) Have access to and copy or remove, at reasonable times, records that are kept under the conditions of this permit;

(3) Inspect at reasonable times, facilities, equipment including monitoring and air pollution control equipment, practices, or operations regulated or required under this permit;

(4) Sample or monitor, at reasonable times, substances or parameters, for the purpose of assuring compliance with the permit or applicable requirements as authorized by the Clean Air Act, the Air Pollution Control Act, or the regulations promulgated under the Acts.

(b) Pursuant to 35 P.S. § 4008, no person shall hinder, obstruct, prevent or interfere with the Department or its personnel in the performance of any duty authorized under the Air Pollution Control Act.

(c) Nothing in this permit condition shall limit the ability of the EPA to inspect or enter the premises of the permittee in accordance with Section 114 or other applicable provisions of the Clean Air Act.

#007 [25 Pa. Code §§ 127.25, 127.444, & 127.512(c)(1)]

Compliance Requirements

(a) The permittee shall comply with the conditions of this permit. Noncompliance with this permit constitutes a violation of the Clean Air Act and the Air Pollution Control Act and is grounds for one (1) or more of the following:

(1) Enforcement action

(2) Permit termination, revocation and reissuance or modification

(3) Denial of a permit renewal application

(b) A person may not cause or permit the operation of a source, which is subject to 25 Pa. Code Article III, unless the source(s) and air cleaning devices identified in the application for the plan approval and operating permit and the plan approval issued to the source are operated and maintained in accordance with specifications in the applications and the conditions in the plan approval and operating permit issued by the Department. A person may not cause or permit the operation of an air contamination source subject to 25 Pa. Code Chapter 127 in a manner inconsistent with good operating practices.

(c) For purposes of Sub-condition (b) of this permit condition, the specifications in applications for plan approvals and operating permits are the physical configurations and engineering design details which the Department determines are essential for the permittee's compliance with the applicable requirements in this Title V permit. Nothing in this sub-condition shall be construed to create an independent affirmative duty upon the permittee to obtain a predetermination from the Department for physical configuration or engineering design detail changes made by the permittee.

#008 [25 Pa. Code § 127.512(c)(2)]

Need to Halt or Reduce Activity Not a Defense

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 in order to maintain compliance with the conditions of this permit.

#009 [25 Pa. Code §§ 127.411(d) & 127.512(c)(5)]

Duty to Provide Information

(a) The permittee shall furnish to the Department, within a reasonable time, information that the Department 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.

(b) Upon request, the permittee shall also furnish to the Department copies of records that the permittee is required to keep by this permit, or for information claimed to be confidential, the permittee may furnish such records directly to the Administrator of EPA along with a claim of confidentiality.

#010 [25 Pa. Code §§ 127.463, 127.512(c)(3) & 127.542]

Reopening and Revising the Title V Permit for Cause

(a) This Title V permit may be modified, revoked, reopened and reissued or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay a permit condition.

(b) This permit may be reopened, revised and reissued prior to expiration of the permit under one or more of the following circumstances:

(1) Additional applicable requirements under the Clean Air Act or the Air Pollution Control Act become applicable to a Title V facility with a remaining permit term of three (3) or more years prior to the expiration date of this permit. The Department will revise the permit as expeditiously as practicable but not later than 18 months after promulgation of the applicable standards or regulations. No such revision is required if the effective date of the requirement is later than the expiration date of this permit, unless the original permit or its terms and conditions has been extended.

(2) Additional requirements, including excess emissions requirements, become applicable to an affected source under the acid rain program. Upon approval by the Administrator of EPA, excess emissions offset plans for an affected source shall be incorporated into the permit.

(3) The Department or the EPA determines that this permit contains a material mistake or inaccurate statements were made in establishing the emissions standards or other terms or conditions of this permit.

(4) The Department or the Administrator of EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

(c) Proceedings to revise this permit shall follow the same procedures which apply to initial permit issuance and shall affect only those parts of this permit for which cause to revise exists. The revision shall be made as expeditiously as practicable.

(d) Regardless of whether a revision is made in accordance with (b)(1) above, the permittee shall meet the applicable standards or regulations promulgated under the Clean Air Act within the time frame required by standards or regulations.

#011 [25 Pa. Code § 127.543]

Reopening a Title V Permit for Cause by EPA

As required by the Clean Air Act and regulations adopted thereunder, this permit may be modified, reopened and reissued, revoked or terminated for cause by EPA in accordance with procedures specified in 25 Pa. Code § 127.543.

SECTION B. General Title V Requirements

#012 [25 Pa. Code § 127.541]

Significant Operating Permit Modifications

When permit modifications during the term of this permit do not qualify as minor permit modifications or administrative amendments, the permittee shall submit an application for significant Title V permit modifications in accordance with 25 Pa. Code § 127.541.

#013 [25 Pa. Code §§ 121.1 & 127.462]

Minor Operating Permit Modifications

(a) The permittee may make minor operating permit modifications (as defined in 25 Pa. Code § 121.1) in accordance with 25 Pa. Code § 127.462.

(b) Unless precluded by the Clean Air Act or the regulations thereunder, the permit shield described in 25 Pa. Code § 127.516 (relating to permit shield) shall extend to an operational flexibility change authorized by 25 Pa. Code § 127.462.

#014 [25 Pa. Code § 127.450]

Administrative Operating Permit Amendments

(a) The permittee may request administrative operating permit amendments, as defined in 25 Pa. Code § 127.450(a), according to procedures specified in § 127.450. Administrative amendments are not authorized for any amendment precluded by the Clean Air Act or the regulations thereunder from being processed as an administrative amendment.

(b) Upon taking final action granting a request for an administrative permit amendment in accordance with § 127.450(c), the Department will allow coverage under 25 Pa. Code § 127.516 (relating to permit shield) for administrative permit amendments which meet the relevant requirements of 25 Pa. Code Article III, unless precluded by the Clean Air Act or the regulations thereunder.

#015 [25 Pa. Code § 127.512(b)]

Severability Clause

The provisions of this permit are severable, and if any provision of this permit is determined by the Environmental Hearing Board or a court of competent jurisdiction to be invalid or unenforceable, such a determination will not affect the remaining provisions of this permit.

#016 [25 Pa. Code §§ 127.704, 127.705 & 127.707]

Fee Payment

(a) The permittee shall pay fees to the Department in accordance with the applicable fee schedules in 25 Pa. Code Chapter 127, Subchapter I (relating to plan approval and operating permit fees).

(b) Emission Fees. The permittee shall, on or before September 1st of each year, pay applicable annual Title V emission fees for emissions occurring in the previous calendar year as specified in 25 Pa. Code § 127.705. The permittee is not required to pay an emission fee for emissions of more than 4,000 tons of each regulated pollutant emitted from the facility.

(c) As used in this permit condition, the term "regulated pollutant" is defined as a VOC, each pollutant regulated under Sections 111 and 112 of the Clean Air Act and each pollutant for which a National Ambient Air Quality Standard has been promulgated, except that carbon monoxide is excluded.

(d) Late Payment. Late payment of emission fees will subject the permittee to the penalties prescribed in 25 Pa. Code § 127.707 and may result in the suspension or termination of the Title V permit. The permittee shall pay a penalty of fifty percent (50%) of the fee amount, plus interest on the fee amount computed in accordance with 26 U.S.C.A. § 6621(a)(2) from the date the emission fee should have been paid in accordance with the time frame specified in 25 Pa. Code § 127.705(c).

(e) The permittee shall pay an annual operating permit administration fee according to the fee schedule established in 25 Pa. Code § 127.704(c) if the facility, identified in Subparagraph (iv) of the definition of the term "Title V facility" in 25 Pa. Code § 121.1, is subject to Title V after the EPA Administrator completes a rulemaking requiring regulation of those sources under Title V of the Clean Air Act.

(f) This permit condition does not apply to a Title V facility which qualifies for exemption from emission fees under 35 P.S. § 4006.3(f).

#017 [25 Pa. Code §§ 127.14(b) & 127.449]

Authorization for De Minimis Emission Increases

(a) This permit authorizes de minimis emission increases from a new or existing source in accordance with 25 Pa. Code §§ 127.14 and 127.449 without the need for a plan approval or prior issuance of a permit modification. The permittee shall provide the Department with seven (7) days prior written notice before commencing any de minimis emissions increase that would result from either: (1) a physical change of minor significance under § 127.14(c)(1); or (2) the construction, installation, modification or reactivation of an air contamination source. The written notice shall:

(1) Identify and describe the pollutants that will be emitted as a result of the de minimis emissions increase.

(2) Provide emission rates expressed in tons per year and in terms necessary to establish compliance consistent with any applicable requirement.

The Department may disapprove or condition de minimis emission increases at any time.

(b) Except as provided below in (c) and (d) of this permit condition, the permittee is authorized during the term of this permit to make de minimis emission increases (expressed in tons per year) up to the following amounts without the need for a plan approval or prior issuance of a permit modification:

(1) Four tons of carbon monoxide from a single source during the term of the permit and 20 tons of carbon monoxide at the facility during the term of the permit.

(2) One ton of NOx from a single source during the term of the permit and 5 tons of NOx at the facility during the term of the permit.

(3) One and six-tenths tons of the oxides of sulfur from a single source during the term of the permit and 8.0 tons of oxides of sulfur at the facility during the term of the permit.

(4) Six-tenths of a ton of PM10 from a single source during the term of the permit and 3.0 tons of PM10 at the facility during the term of the permit. This shall include emissions of a pollutant regulated under Section 112 of the Clean Air Act unless precluded by the Clean Air Act or 25 Pa. Code Article III.

(5) One ton of VOCs from a single source during the term of the permit and 5.0 tons of VOCs at the facility during the term of the permit. This shall include emissions of a pollutant regulated under Section 112 of the Clean Air Act unless precluded by the Clean Air Act or 25 Pa. Code Article III.

(c) In accordance with § 127.14, the permittee may install the following minor sources without the need for a plan approval:

(1) Air conditioning or ventilation systems not designed to remove pollutants generated or released from other sources.

(2) Combustion units rated at 2,500,000 or less Btu per hour of heat input.

(3) Combustion units with a rated capacity of less than 10,000,000 Btu per hour heat input fueled by natural gas supplied by a public utility, liquefied petroleum gas or by commercial fuel oils which are No. 2 or lighter, viscosity less

than or equal to 5.82 c St, and which meet the sulfur content requirements of 25 Pa. Code § 123.22 (relating to combustion units). For purposes of this permit, commercial fuel oil shall be virgin oil which has no reprocessed, recycled or waste material added.

(4) Space heaters which heat by direct heat transfer.

(5) Laboratory equipment used exclusively for chemical or physical analysis.

(6) Other sources and classes of sources determined to be of minor significance by the Department.

(d) This permit does not authorize de minimis emission increases if the emissions increase would cause one or more of the following:

(1) Increase the emissions of a pollutant regulated under Section 112 of the Clean Air Act except as authorized in Subparagraphs (b)(4) and (5) of this permit condition.

(2) Subject the facility to the prevention of significant deterioration requirements in 25 Pa. Code Chapter 127, Subchapter D and/or the new source review requirements in Subchapter E.

(3) Violate any applicable requirement of the Air Pollution Control Act, the Clean Air Act, or the regulations promulgated under either of the acts.

(4) Changes which are modifications under any provision of Title I of the Clean Air Act and emission increases which would exceed the allowable emissions level (expressed as a rate of emissions or in terms of total emissions) under the Title V permit.

(e) Unless precluded by the Clean Air Act or the regulations thereunder, the permit shield described in 25 Pa. Code § 127.516 (relating to permit shield) applies to de minimis emission increases and the installation of minor sources made pursuant to this permit condition.

(f) Emissions authorized under this permit condition shall be included in the monitoring, recordkeeping and reporting requirements of this permit.

(g) Except for de minimis emission increases allowed under this permit, 25 Pa. Code § 127.449, or sources and physical changes meeting the requirements of 25 Pa. Code § 127.14, the permittee is prohibited from making physical changes or engaging in activities that are not specifically authorized under this permit without first applying for a plan approval. In accordance with § 127.14(b), a plan approval is not required for the construction, modification, reactivation, or installation of the sources creating the de minimis emissions increase.

(h) The permittee may not meet de minimis emission threshold levels by offsetting emission increases or decreases at the same source.

#018 [25 Pa. Code §§ 127.11a & 127.215]

Reactivation of Sources

(a) The permittee may reactivate a source at the facility that has been out of operation or production for at least one year, but less than or equal to five (5) years, if the source is reactivated in accordance with the requirements of 25 Pa. Code §§ 127.11a and 127.215. The reactivated source will not be considered a new source.

(b) A source which has been out of operation or production for more than five (5) years but less than 10 years may be reactivated and will not be considered a new source if the permittee satisfies the conditions specified in 25 Pa. Code § 127.11a(b).

SECTION B. General Title V Requirements

#019 [25 Pa. Code §§ 121.9 & 127.216]

Circumvention

(a) The owner of this Title V facility, or any other person, may not circumvent the new source review requirements of 25 Pa. Code Chapter 127, Subchapter E by causing or allowing a pattern of ownership or development, including the phasing, staging, delaying or engaging in incremental construction, over a geographic area of a facility which, except for the pattern of ownership or development, would otherwise require a permit or submission of a plan approval application.

(b) No person may permit the use of a device, stack height which exceeds good engineering practice stack height, dispersion technique or other technique which, without resulting in reduction of the total amount of air contaminants emitted, conceals or dilutes an emission of air contaminants which would otherwise be in violation of this permit, the Air Pollution Control Act or the regulations promulgated thereunder, except that with prior approval of the Department, the device or technique may be used for control of malodors.

#020 [25 Pa. Code §§ 127.402(d) & 127.513(1)]

Submissions

(a) Reports, test data, monitoring data, notifications and requests for renewal of the permit shall be submitted to the:

Regional Air Program Manager
PA Department of Environmental Protection
(At the address given on the permit transmittal letter,
or otherwise notified)

(b) Any report or notification for the EPA Administrator or EPA Region III should be addressed to:

Air Enforcement Branch (3AP00)
United States Environmental Protection Agency
Region 3
1650 Arch Street
Philadelphia, PA 19103-2029

(c) An application, form, report or compliance certification submitted pursuant to this permit condition shall contain certification by a responsible official as to truth, accuracy, and completeness as required under 25 Pa. Code § 127.402(d). Unless otherwise required by the Clean Air Act or regulations adopted thereunder, this certification and any other certification required pursuant to this permit shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

#021 [25 Pa. Code §§ 127.441(c) & 127.463(e); Chapter 139; & 114(a)(3), 504(b) of the CAA]

Sampling, Testing and Monitoring Procedures

(a) The permittee shall perform the emissions monitoring and analysis procedures or test methods for applicable requirements of this Title V permit. In addition to the sampling, testing and monitoring procedures specified in this permit, the Permittee shall comply with any additional applicable requirements promulgated under the Clean Air Act after permit issuance regardless of whether the permit is revised.

(b) The sampling, testing and monitoring required under the applicable requirements of this permit, shall be conducted in accordance with the requirements of 25 Pa. Code Chapter 139 unless alternative methodology is required by the Clean Air Act (including §§ 114(a)(3) and 504(b)) and regulations adopted thereunder.

#022 [25 Pa. Code §§ 127.511 & Chapter 135]

Recordkeeping Requirements

(a) The permittee shall maintain and make available, upon request by the Department, records of required monitoring information that include the following:

(1) The date, place (as defined in the permit) and time of sampling or measurements.

(2) The dates the analyses were performed.

(3) The company or entity that performed the analyses.

(4) The analytical techniques or methods used.

(5) The results of the analyses.

(6) The operating conditions as existing at the time of sampling or measurement.

(b) The permittee shall retain records of the required monitoring data and supporting information for at least five (5) years from the date of the monitoring sample, measurement, report or application. Supporting information includes the calibration data and maintenance records and original strip-chart recordings for continuous monitoring instrumentation, and copies of reports required by the permit.

(c) The permittee shall maintain and make available to the Department upon request, records including computerized records that may be necessary to comply with the reporting, recordkeeping and emission statement requirements in 25 Pa. Code Chapter 135 (relating to reporting of sources). In accordance with 25 Pa. Code Chapter 135, § 135.5, such records may include records of production, fuel usage, maintenance of production or pollution control equipment or other information determined by the Department to be necessary for identification and quantification of potential and actual air contaminant emissions. If direct recordkeeping is not possible or practical, sufficient records shall be kept to provide the needed information by indirect means.

#023 [25 Pa. Code §§ 127.411(d), 127.442, 127.463(e) & 127.511(c)]

Reporting Requirements

(a) The permittee shall comply with the reporting requirements for the applicable requirements specified in this Title V permit. In addition to the reporting requirements specified herein, the permittee shall comply with any additional applicable reporting requirements promulgated under the Clean Air Act after permit issuance regardless of whether the permit is revised.

(b) Pursuant to 25 Pa. Code § 127.511(c), the permittee shall submit reports of required monitoring at least every six (6) months unless otherwise specified in this permit. Instances of deviations (as defined in 25 Pa. Code § 121.1) from permit requirements shall be clearly identified in the reports. The reporting of deviations shall include the probable cause of the deviations and corrective actions or preventative measures taken, except that sources with continuous emission monitoring systems shall report according to the protocol established and approved by the Department for the source. The required reports shall be certified by a responsible official.

(c) Every report submitted to the Department under this permit condition shall comply with the submission procedures specified in Section B, Condition #020(c) of this permit.

(d) Any records, reports or information obtained by the Department or referred to in a public hearing shall be made available to the public by the Department except for such records, reports or information for which the permittee has shown cause that the documents should be considered confidential and protected from disclosure to the public under Section 4013.2 of the Air Pollution Control Act and consistent with Sections 112(d) and 114(c) of the Clean Air Act and 25 Pa. Code § 127.411(d). The permittee may not request a claim of confidentiality for any emissions data generated for the Title V facility.

#024 [25 Pa. Code § 127.513]

Compliance Certification

(a) One year after the date of issuance of the Title V permit, and each year thereafter, unless specified elsewhere in the permit, the permittee shall submit to the Department and EPA Region III a certificate of compliance with the terms and conditions in this permit, for the previous year, including the emission limitations, standards or work practices. This certification shall include:

(1) The identification of each term or condition of the permit that is the basis of the certification.

(2) The compliance status.

(3) The methods used for determining the compliance status of the source, currently and over the reporting period.

(4) Whether compliance was continuous or intermittent.

(b) The compliance certification should be postmarked or hand-delivered within thirty days of each anniversary date of the date of issuance or, of the submittal date specified elsewhere in the permit, to the Department and EPA in accordance with the submission requirements specified in condition #020 of this section.

#025 [25 Pa. Code § 127.3]

Operational Flexibility

(a) The permittee is authorized to make changes within the Title V facility in accordance with the following provisions in 25 Pa. Code Chapter 127 which implement the operational flexibility requirements of Section 502(b)(10) of the Clean Air Act and Section 6.1(i) of the Air Pollution Control Act:

(1) Section 127.14 (relating to exemptions)

(2) Section 127.447 (relating to alternative operating scenarios)

(3) Section 127.448 (relating to emissions trading at facilities with Federally enforceable emissions caps)

(4) Section 127.449 (relating to de minimis emission increases)

(5) Section 127.450 (relating to administrative operating permit amendments)

(6) Section 127.462 (relating to minor operating permit amendments)

(7) Subchapter H (relating to general plan approvals and operating permits)

(b) Unless precluded by the Clean Air Act or the regulations adopted thereunder, the permit shield authorized under 25 Pa. Code § 127.516 shall extend to operational flexibility changes made at this Title V facility pursuant to this permit condition and other applicable operational flexibility terms and conditions of this permit.

#026 [25 Pa. Code §§ 127.441(d), 127.512(i) and 40 CFR Part 68]

Risk Management

(a) If required by Section 112(r) of the Clean Air Act, the permittee shall develop and implement an accidental release program consistent with requirements of the Clean Air Act, 40 CFR Part 68 (relating to chemical accident prevention provisions) and the Federal Chemical Safety Information, Site Security and Fuels Regulatory Relief Act (P.L. 106-40).

(b) The permittee shall prepare and implement a Risk Management Plan (RMP) which meets the requirements of Section 112(r) of the Clean Air Act, 40 CFR Part 68 and the Federal Chemical Safety Information, Site Security and Fuels Regulatory Relief Act when a regulated substance listed in 40 CFR § 68.130 is present in a process in more than the listed threshold quantity at the Title V facility. The permittee shall submit the RMP to the federal Environmental Protection Agency according to the following schedule and requirements:

(1) The permittee shall submit the first RMP to a central point specified by EPA no later than the latest of the following:

(i) Three years after the date on which a regulated substance is first listed under § 68.130; or,

(ii) The date on which a regulated substance is first present above a threshold quantity in a process.

(2) The permittee shall submit any additional relevant information requested by the Department or EPA concerning the RMP and shall make subsequent submissions of RMPs in accordance with 40 CFR § 68.190.

(3) The permittee shall certify that the RMP is accurate and complete in accordance with the requirements of 40 CFR Part 68, including a checklist addressing the required elements of a complete RMP.

(c) As used in this permit condition, the term "process" shall be as defined in 40 CFR § 68.3. The term "process" means any activity involving a regulated substance including any use, storage, manufacturing, handling, or on-site movement of such substances or any combination of these activities. For purposes of this definition, any group of vessels that are interconnected, or separate vessels that are located such that a regulated substance could be involved in a potential release, shall be considered a single process.

(d) If the Title V facility is subject to 40 CFR Part 68, as part of the certification required under this permit, the permittee shall:

(1) Submit a compliance schedule for satisfying the requirements of 40 CFR Part 68 by the date specified in 40 CFR § 68.10(a); or,

(2) Certify that the Title V facility is in compliance with all requirements of 40 CFR Part 68 including the registration and submission of the RMP.

(e) If the Title V facility is subject to 40 CFR Part 68, the permittee shall maintain records supporting the implementation of an accidental release program for five (5) years in accordance with 40 CFR § 68.200.

(f) When the Title V facility is subject to the accidental release program requirements of Section 112(r) of the Clean Air Act and 40 CFR Part 68, appropriate enforcement action will be taken by the Department if:

(1) The permittee fails to register and submit the RMP or a revised plan pursuant to 40 CFR Part 68.

(2) The permittee fails to submit a compliance schedule or include a statement in the compliance certification required under Condition #24 of Section B of this Title V permit that the Title V facility is in compliance with the requirements of Section 112(r) of the Clean Air Act, 40 CFR Part 68, and 25 Pa. Code § 127.512(i).

#027 [25 Pa. Code § 127.512(e)]

Approved Economic Incentives and Emission Trading Programs

No permit revision shall be required under approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this Title V permit.

#028 [25 Pa. Code §§ 127.516, 127.450(d), 127.449(f) & 127.462(g)]

Permit Shield

(a) The permittee's compliance with the conditions of this permit shall be deemed in compliance with applicable requirements (as defined in 25 Pa. Code § 121.1) as of the date of permit issuance if either of the following applies:

(1) The applicable requirements are included and are specifically identified in this permit.

(2) The Department specifically identifies in the permit other requirements that are not applicable to the permitted facility or source.

(b) Nothing in 25 Pa. Code § 127.516 or the Title V permit shall alter or affect the following:

(1) The provisions of Section 303 of the Clean Air Act, including the authority of the Administrator of the EPA provided thereunder.

(2) The liability of the permittee for a violation of an applicable requirement prior to the time of permit issuance.

(3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act.

(4) The ability of the EPA to obtain information from the permittee under Section 114 of the Clean Air Act.

(c) Unless precluded by the Clean Air Act or regulations thereunder, final action by the Department on minor or significant permit modifications, and operational flexibility changes shall be covered by the permit shield. Upon taking final action granting a request for an administrative permit amendment, the Department will allow coverage of the amendment by the permit shield in § 127.516 for administrative amendments which meet the relevant requirements of 25 Pa. Code Article III.

(d) The permit shield authorized under § 127.516 is in effect for the permit terms and conditions in this Title V permit, including administrative operating permit amendments and minor operating permit modifications.

SECTION C. Site Level Requirements

I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.1]

Prohibition of certain fugitive emissions

(a) No person may permit the emission into the outdoor atmosphere of fugitive air contaminants from a source other than the following:

(1) Construction or demolition of buildings or structures.

(2) Grading, paving and maintenance of roads and streets.

(3) Use of roads and streets. Emissions from material in or on trucks, railroad cars and other vehicular equipment are not considered as emissions from use of roads and streets.

(4) Clearing of land.

(5) Stockpiling of materials.

(6) Open burning operations.

(7) Sources and classes of sources other than those identified above, for which the permittee has obtained a determination from the Department that fugitive emissions from the source, after appropriate control, meet the following requirements:

(i) The emissions are of minor significance with respect to causing air pollution.

(ii) The emissions are not preventing or interfering with the attainment or maintenance of any ambient air quality standard.

 # 002 [25 Pa. Code §123.2]

Fugitive particulate matter

No person may permit fugitive particulate matter to be emitted into the outdoor atmosphere from a source specified in condition #001(a)(1) - (a)(7) above if the emissions are visible at the point the emissions pass outside the person's property.

 # 003 [25 Pa. Code §123.41]

Limitations

No person may permit the emission into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following:

(1) Equal to or greater than 20% for a period or periods aggregating more than three minutes in any 1 hour.

(2) Equal to or greater than 60% at any time.

 # 004 [25 Pa. Code §123.42]

Exceptions

The emission limitations of 25 Pa Code Section 123.41 shall not apply when:

(1) The presence of uncombined water is the only reason for failure of the emission to meet the limitations;

(2) The emission results from the operation of equipment used solely to train and test persons in observing the opacity of visible emissions;

(3) The emissions results from sources specified in 25 Pa Code Section 123.1(a)(1)-(9).

Fuel Restriction(s).

 # 005 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 123.22 and 127.511]

The sulfur content of the #2 and lighter fuel oil delivered to this facility shall not exceed 0.5% (by weight).

II. TESTING REQUIREMENTS.

 # 006 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall perform tests (in accordance with the provisions of 25 Pa. Code Chapter 139) or provide a fuel certification report of the percent sulfur by weight of each delivery of the fuel oil delivered to this facility.

OR

The permittee shall keep records of the fuel certification reports obtained yearly from the fuel oil supplier stating that the sulfur percentage for each shipment of fuel oil delivered to the facility during the year shall not exceed 0.5% sulfur by weight.

 # 007 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code 139.2 and 127.511]

(a) The stack testing required by this permit shall be performed using EPA reference test methods approved by the Department.

(b) At least sixty (60) days prior to the performance of this stack testing, a test plan shall be submitted to the Department for evaluation. The plan shall contain a description of the proposed test methods and dimensioned drawings or sketches showing the test port locations.

(c) The Department (Northcentral Regional Office and Central Office, Source Testing Section) shall be given at least fourteen (14) days advance notice of the scheduled dates for the performance of this stack testing. The Department is under no obligation to accept the results of the testing without having been given proper notification.

(d) Within sixty (60) days of the completion of this stack testing, two (2) copies of the test report shall be submitted to the Department (Northcentral Regional Office). The report shall contain the results of the tests, a description of the testing and analytical procedures actually used in performance of the tests, all process and operating data collected during the tests, a copy of all raw data, and a copy of all calculations generated during data analysis.

 # 008 [25 Pa. Code §139.1]

Sampling facilities.

Upon the request of the Department, the person responsible for a source shall provide adequate sampling ports, safe sampling platforms and adequate utilities for the performance by the Department of tests on such source. The Department will set forth, in the request, the time period in which the facilities shall be provided as well as the specifications for such facilities.

 # 009 [25 Pa. Code §139.11]

General requirements.

(a) As specified in 25 Pa. Code Section 139.11(1), performance tests shall be conducted while the source is operating at maximum routine operating conditions or under such other conditions, within the capacity of the equipment, as may be requested by the Department.

(b) As specified in 25 Pa. Code Section 139.11(2), the Department will consider test results for approval where sufficient information is provided to verify the source conditions existing at the time of the test and where adequate data is available to show the manner in which the test was conducted. Information submitted to the Department shall include, as a minimum all of the following:

(1) A thorough source description, including a description of any air cleaning devices and the flue.

(2) Process conditions, for example, the charging rate of raw materials or the rate of production of final product, boiler pressure, oven temperature and other conditions which may effect emissions from the process.

(3) The location of sampling ports.

(4) Effluent characteristics, including velocity, temperature, moisture content, gas density (percentage CO, CO2, O2 and N2), static and barometric pressures.

(5) Sample collection techniques employed, including procedures used, equipment descriptions and data to verify that isokinetic sampling for particulate matter collection occurred and that acceptable test conditions were met.

(6) Laboratory procedures and results.

(7) Calculated results.

III. MONITORING REQUIREMENTS.

 # 010 [25 Pa. Code §123.43]

Measuring techniques

Visible emissions may be measured using either of the following:

(1) A device approved by the Department and maintained to provide accurate opacity measurements.

(2) Observers, trained and certified, to measure plume opacity with the naked eye or with the aid of any devices approved by the Department.

 # 011 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall conduct a weekly inspection of the facility during daylight hours while the facility is operating to detect visible emissions, visible fugitive emissions and malodors. Weekly inspections are necessary to determine:

(1) the presence of visible emissions.

(2) the presence of visible fugitive emissions.

(3) the presence of malodors beyond the boundaries of the facility.

(b) All detected visible emissions, visible fugitive emissions or malodors that have the potential to exceed applicable limits shall be reported to the manager of the facility.

IV. RECORDKEEPING REQUIREMENTS.

 # 012 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall maintain a logbook of the weekly facility inspections performed. The logbook shall include the name of the company representative performing the weekly inspection, the date and time of inspections, any instances of exceedances of visible emissions limitations, visible fugitive emissions limitations and malodorous air emissions limitations, and the name of the manager informed if a potential exceedance is observed. The permittee shall also record any and all corrective action(s) taken to abate each recorded deviation to prevent future occurrences.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

 # 013 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall keep accurate and comprehensive records of all information specified in 40 CFR Section 98.3(g)(1) - (7).

All information generated to comply with this recordkeeping condition shall be kept for minimum of three (3) years and shall be made available to the Department upon request.

 # 014 [25 Pa. Code §135.5]

Recordkeeping

The permittee shall maintain and make available upon request by the Department records including computerized records that may be necessary to comply with 135.3 and 135.21 (relating to reporting; and emissions statements). These may include records of production, fuel usage, maintenance of production or pollution control equipment or other information determined by the Department to be necessary for identification and quantification of potential and actual air contaminant emissions.

V. REPORTING REQUIREMENTS.

 # 015 [25 Pa. Code §127.441]

Operating permit terms and conditions.

(a) The permittee shall submit the annual compliance certifications to the Department and EPA Region III, as specified in Condition #024 of Section B, General Title V Requirements, no later than September 1 (from July of the previous year through June of the current year).

(b) The permittee shall submit the semiannual reports of required monitoring to the Department, as specified in Condition #023 of Section B, General Title V Requirements, no later than September 1 (for January through June) and March 1 (for July through December of the previous year).

 # 016 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Upon request by the Department, the permittee shall submit all requested reports in accordance with the Department's suggested format.

 # 017 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 40 CFR Section 98.3(b)]

The annual GHG emissions report shall be submitted by not later than March 31 of each calendar year for GHG emissions in the previous calendar year. The provisions specified in 40 CFR Section 98.3(b)(1) - (3) are applicable.

 # 018 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 40 CFR Section 98.3(c)]

The content of the annual GHG report submitted annually shall contain all information specified in the provisions of 40

CFR Sections 98.3(c)(1) - (9). The permittee shall assure each report be certified by the designated representative and submitted electronically in a format prescribed by EPA and/or the Department.

 # 019 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 40 CFR Section 98.3(h)]

The permittee shall submit revisions to a GHG report within 45 days of discovering a revision is needed or being notified by the Department of errors in the GHG report. Any revisions shall be kept for a minimum of three (3) years.

 # 020 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall comply with the provisions specified in 40 CFR Section 98.4 including the submission of a certificate of representation at least 60 days prior to deadline for submission of initial report.

 # 021 [25 Pa. Code §127.442]

Reporting requirements.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall report each malfunction that poses an imminent and substantial danger to the public health and safety or the environment or which it should reasonably believe may result in citizens compliants to the Department that occurs at this facility. For purposes of this condition a malfunction is defined as 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 that may result in an increase in the emissions of air contaminants.

(b) When the malfunction poses an imminent and substantial danger to the public health and safety, the notification shall be submitted to the Department no later than one hour after the incident.

(1) The notice shall describe the:

(i) name and location of the facility;
(ii) nature and cause of the malfunction;
(iii) time when the malfunction or breakdown was first observed;
(iv) expected duration of excess emissions; and
(v) estimated rate of emissions.

(2) The permittee shall notify the Department immediately when corrective measures have been accomplished.

(3) Subsequent to the malfunction, the owner or operator shall submit a full report on the malfunction to the Department within 15 days, if requested.

(4) The permittee shall submit reports on the operation and maintenance of the source to the Regional Air Program Manager at such intervals and in such form and detail as may be required by the Department. Information required in the reports may include, but is not limited to, process weight rates, firing rates, hours of operation, and maintenance schedules.

(c) Malfunctions shall be reported to the Department at the following address:

Air Program Manager
Pennsylvania Department of Environmental Protection
Air Quality Program
208 West Third Street, Suite 101
Williamsport, PA 17701-6448

 # 022 [25 Pa. Code §135.21]

Emission statements

(a) The permittee shall provide the Department with a statement of each stationary source in a form as prescribed by the Department, showing the actual emissions of oxides of nitrogen and volatile organic compounds (VOCs) from the permitted facility for each reporting period, a description of the method used to calculate the emissions and the time period over which the calculation is based.

(b) The annual emission statements are due by March 1 for the preceding calendar year and shall contain a certification by a company officer or the plant manager that the information contained in the statement is accurate. The Emission Statement shall provide data consistent with requirements and guidance developed by the EPA.

(c) The Department may require more frequent submittals if the Department determines that one or more of the following applies:

(1) A more frequent submission is required by the EPA.

(2) Analysis of the data on a more frequent basis is necessary to implement the requirements of the Air Pollution Control Act.

 # 023 [25 Pa. Code §135.3]

Reporting

(a) A permittee to which 25 Pa. Code Chapter 135 applies, and who has previously been advised by the Department to submit an annual Air Information Management Systems (AIMS) report, shall submit by March 1 of each year an annual AIMS report for the preceding calendar year. The report shall include information for all previously reported sources, new sources which were first operated during the preceding calendar year and sources modified during the same period which were not previously reported.

(b) A person who receives initial notification by the Department that an annual AIMS report is necessary shall submit an initial annual AIMS report within 60 days after receiving the notification or by March 1 of the year following the year for which the report is required, whichever is later.

(c) The permittee may request an extension of time from the Department for the filing of a source report, and the Department may grant the extension for reasonable cause.

VI. WORK PRACTICE REQUIREMENTS.

 # 024 [25 Pa. Code §123.1]

Prohibition of certain fugitive emissions

The permittee shall take all reasonable actions for any source specified in 25 Pa Code Section 123.1(a)(1-7) or (9) to prevent particulate matter from becoming airborne. These actions shall include, but not be limited to, the following:

(1) Use, where possible, of water or chemicals for control of dust in the demolition of buildings or structures, construction operations, the grading of roads or the clearing of land.

(2) Application of asphalt, oil, water or suitable chemicals on dirt roads, material stockpiles and other surfaces which may give rise to airborne dusts.

(3) Paving and maintenance of roadways.

(4) Prompt removal of earth or other material from paved streets onto which earth or other material has been transported by trucking or earth moving equipment, erosion by water, or other means.

SECTION C. Site Level Requirements

VII. ADDITIONAL REQUIREMENTS.

 # 025 [25 Pa. Code §121.7]

Prohibition of air pollution.

No person may permit air pollution as that term is defined in the act (The Air Pollution Control Act (35 P.S. §§ 4001-4015)).

 # 026 [25 Pa. Code §123.31]

Limitations

No person may permit the emission into the outdoor atmosphere of any malodorous air contaminants from any source in a manner that the malodors are detectable outside the property of the person on whose land the source is being operated.

 # 027 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 40 CFR Section 98.2(a)(1)]

The electricity generating units associated with Source IDs 031 through 034 are listed in Table A-3 to Subpart A of 40 CFR Part 98 which subject sources at the Shawville plant to the greenhouse gas (GHG) emissions reporting requirements of 40 CFR Part 98.

 # 028 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 40 CFR Section 98.2(i)]

The permittee shall continue to comply with the requirements of 40 CFR Part 98 including the requirement to submit annual GHG emissions reports even if the facilities does not meet the applicability requirements specified in 40 CFR Section 98.2(a) in a future year. The provisions specified in 40 CFR Section 98.2(i)(1) - (3) are applicable.

 # 029 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 40 CFR Section 98.3(e)]

For the GHG emissions in each annual report, the permittee shall use the calculation methodologies specified in the relevant subparts of 40 CFR Part 98. For each source category, the permittee shall use the same calculation methodology throughout the entire report period unless written explanation of why a change in methodology is necessary.

The provisions specified in 40 CFR Section 98.3(f) are applicable.

 # 030 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The provisions of 40 CFR Section 98.8 are applicable.

 # 031 [25 Pa. Code §129.14]

Open burning operations

No person may permit the open burning of material at this facility unless in accordance with 25 Pa. Code Section 129.14.

VIII. COMPLIANCE CERTIFICATION.

No additional compliance certifications exist except as provided in other sections of this permit including Section B (relating to Title V General Requirements).

IX. COMPLIANCE SCHEDULE.

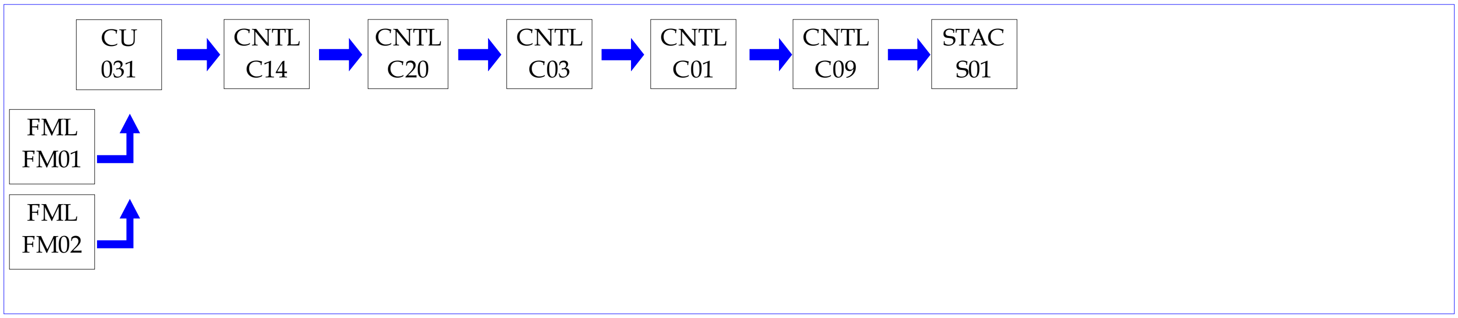
No compliance milestones exist.

***** Permit Shield In Effect *****

SECTION D. Source Level Requirements

Source ID: 031 Source Name: UTILITY BOILER - UNIT 1

Source Capacity/Throughput: 1,345.000 MMBTU/HR



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.11]

Combustion units

No person may permit the emission into the outdoor atmosphere of particulate matter from the exhaust of Source ID 031 in excess of 0.1 pound per million Btu of heat input.

 # 002 [25 Pa. Code §123.22]

Combustion units

(a) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 031 in excess of the rate of 4 pounds per million Btu of heat input over any 1-hour period when firing #2 fuel oil.

(b) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 031 in excess of the pounds of SO2 per 10^6 Btu heat input as shown below when firing solid fossil fuels:

Thirty-day running average not to be exceeded at any time: 3.7 lbs./10^6 Btu

Daily average not to be exceeded more than 2 days in any running 30-day period: 4.0 lbs./10^6 Btu

Daily average not to be exceeded at any time: 4.8 lbs./10^6 Btu

 # 003 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 through 129.95 and 40 CFR Section 76.5(a)(1)]

The nitrogen oxides emissions (NOx, expressed as NO2) from the exhaust of Source ID 031 shall not exceed 0.524 pounds per million BTU of heat input based on a 30 day rolling average.

 # 004 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The ammonia (NH3) emission rate from the exhaust of Source ID 031 shall not exceed 0.003 lbs/MMBTU of heat input.

 # 005 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The ammonia slip resulting from the operation of each SNCR system associated with Source IDs 031, 032, 033 and 034 shall not exceed 5 ppmv corrected to 8% oxygen.

 # 006 [25 Pa. Code §127.531]

Special conditions related to acid rain.

(a) The permittee shall not emit into the outdoor atmosphere, annual emissions of sulfur dioxide in excess of the number of allowances to emit sulfur dioxide that the permittee or designated representative holds for each affected source.

(b) The permittee shall not emit sulfur dioxide in a manner that would exceed applicable emission rates or standards, including ambient air quality standards.

(c) The permittee shall not use a sulfur dioxide allowance prior to the year for which the allowance is allocated.

(d) A limit will not be placed on the number of sulfur dioxide allowances held for a source. The permittee shall not, however, use allowances as a defense to noncompliance with other applicable requirements.

(e) The permittee shall account for all allowances in accordance with the procedures established in regulations promulgated under Title IV of the Clean Air Act.

 # 007 [40 CFR Part 52 Approval And Promulgation of Implementation Plans §40 CFR 52.2020]

Subpart NN--Pennsylvania

Identification of plan.

No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 031 in excess of the rate of 4 pounds per million Btu of heat input at any time.

Fuel Restriction(s).

 # 008 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 123.22]

The sulfur content of the #2 and lighter fuel oil fired in Source ID 031 shall not exceed 0.5% (by weight).

 # 009 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from RFD condition approved April 8, 2002]

The only binding agents to be used in manufacturing the synthetic fuels used at the Shawville Station shall be soybean oil, Accretion Technologies FTH-100, Nalco 9838, Dow Covol 298 and Dow Covol 298-1 having the compositions identified in the materials submitted with the request for determination dated February 18, 2002 and approved on April 8, 2002. Additionally, the maximum application rate of the soybean oil shall be 1.0% by weight of the soybean oil/coal mixture and the maximum application rate of any of the other four binding agents shall be such that the maximum application rate of the combined non-water constituents contained in the binding agent shall never exceed 1.0% by weight of the binding agent/coal mixture.

II. TESTING REQUIREMENTS.

 # 010 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable testing requirements specified in 25 Pa. Code Chapter 139 and the Departments "Source Testing Manual."

 # 011 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall conduct testing of the SNCR systems between January 1, 2014 and December 31, 2014 and every five years thereafter. The permittee shall conduct the following testing upon the exhaust of the utility boilers:

(a) The ammonia testing shall be conducted upon the exhausts of Source IDs 031 and Source ID 032, respectively, and the common exhaust of Source IDs 033 and 034 using EPA reference method stack testing or an alternative ammonia test method approved by the Department to determine ammonia slip levels and ammonia emissions from each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034.

(b) During the stack testing, the permittee shall measure and, record the gross megawatt load, NOx emissions and SNCR ammonia slip levels for each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034, and such information shall be provided in the stack test report submitted to the Department.

 # 012 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

Between January 1, 2014 and December 31, 2014 and every five years thereafter, the permittee shall perform stack testing on the four utility boilers (Source IDs 031, 032, 033 and 034) to demonstrate compliance with the particulate matter emission limitation contained in this operating permit. Stack testing shall be performed in accordance with the applicable provisions of 25 Pa. Code Chapter 139 (relating to sampling and testing) using test methods and procedures approved by the Department. Testing must be performed while the sources are operating at maximum routine operating conditions.

III. MONITORING REQUIREMENTS.

 # 013 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 123.25, 123.46, 123.51, 40 CFR Part 75, and 40 CFR Sections 64.3 and 64.6]

(a) The permittee shall install, calibrate, maintain and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxide emissions, either oxygen or carbon dioxide concentration and volumetric flow in accordance with all applicable requirements specified in, or established pursuant to: 25 Pa. Code Chapters 123 and 139, the Department's "Continuous Source Monitoring Manual" and 40 CFR Part 75.

(b) All continuous emissions monitoring systems shall be tested in accordance with all applicable requirements specified in 25 Pa. Code Chapter 139, the Departments "Continuous Source Monitoring Manual" and 40 CFR Part 75.

 # 014 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511 and 40 CFR Sections 64.3 and 64.6]

The permittee shall comply with all applicable monitoring requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 015 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall install and maintain instrumentation to monitor and record the ammonia injection rate of the SNCR systems associated with Source IDs 031, 032, 033, and 034 on a continuous basis. Additionally, the permittee shall continuously monitor and record the gross megawatt load and NOx emissions associated with the boilers.

These records shall be retained for a minimum of five years and shall be presented to the Department upon request.

IV. RECORDKEEPING REQUIREMENTS.

 # 016 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable recordkeeping requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 017 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall keep records of the data and calculations used to verify compliance with the particulate matter, sulfur oxides (SOx) and ammonia (NH3) emissions limitations for Source ID 031.

(b) The permittee shall keep records of the tests conducted or certification reports used to verify the sulfur content (percent by weight) of the fuel oil.

These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

 # 018 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

(a) The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95.

(b) The permittee shall keep records, including data which clearly demonstrates that the NOX emission limits for Source ID 031 are met.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

 # 019 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall keep records of the opacity reading from the continuous opacity monitoring system (COMS) associated with Source ID 031.

(b) The permittee shall keep records of all inspections, repairs, and maintenance performed on the COMS associated with Source ID 031.

(c) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 020 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall record all excursions and corrective actions taken in response to an excursion and the time elapsed until the corrective actions have been taken.

(b) The permittee shall keep records of all monitoring downtime incidents associated with the COMS associated with Source ID 031. The permittee shall also record the dates, times and durations, possible causes, and corrective actions taken for the incidents.

(c) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 021 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall keep records of the calculations, including ammonia emissions test reports, used to determine compliance with the SNCR ammonia slip emissions limitations for Source IDs 031, 032, 033 and 034. These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

 # 022 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable reporting requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 023 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9 and Section 70.6(a)(3)(iii)(A)]

(a) The permittee shall submit reports to the Department on a semi-annual basis that include the records of all excursions and corrective actions taken, the dates, times, durations, and possible causes.

(b) The permittee shall submit reports to the Department on a semi-annual basis that include all monitoring downtime incidents, their dates, times and durations, possible causes, and corrective actions taken.

(c) The semi-annual reports shall be submitted to the Department no later than March 1 (for July 1 through December 31 of the previous year) and September 1 (for January 1 through June 30 of the current year).

 # 024 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit permit condition is also derived from 40 CFR Section 98.42]

The permittee shall report the annual mass emissions of CO2, N20, and CH4 from Source IDs 031 through 034 in accordance with the requirements of 40 CFR Part 98 Subpart D.

 # 025 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit permit condition is also derived from 40 CFR Section 98.43]

The permittee shall calculate and report the annual N20 and CH4 mass emissions from Source IDs 031 through 034 by following the applicable method specified in 40 CFR Section 98.33(c).

VI. WORK PRACTICE REQUIREMENTS.

 # 026 [25 Pa. Code §127.441]

Operating permit terms and conditions.

No reclaimed or waste oil or oil that contains any waste material shall be used as fuel in the lighter associated with the low NOX burners of Source ID 031.

 # 027 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 129.91]

The permittee shall maintain and operate Source ID 031 in accordance with the manufacturers specifications. This requirement shall be considered as VOC RACT for Source ID 031.

 # 028 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The SNCR systems (Control Device IDs C20, C21, C22, and C23) shall be operated in accordance with the manufacturer specifications and good air pollution control practices.

VII. ADDITIONAL REQUIREMENTS.

 # 029 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source ID 031 is a 1954 vintage, Babcock Wilcox, dry bottom, front wall-fired, balanced draft, divided furnace drum type utility boiler with a rated heat input of 1,345 MMBtu/hr. The boiler is fueled with pulverized bituminous coal/synfuel or #2 oil. The air contaminant emissions from the subject boiler shall be controlled by 16 Dual Register Low NOX (DRB-XCL) Babcock and Wilcox burners (Control Device ID C14), a NH3/SO3 injection flue gas conditioning system (Control Device ID C03) and a two stage Research Cottrell & Buell electrostatic precipitator (Control Device IDs C01 and C09).

The nitrogen oxides emissions from Source ID 031 may further be controlled by an Energy System Associates selective non-catalytic reduction system (Control Device ID C20).

 # 030 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511 and 40 CFR Sections 64.3 and 64.6]

Any opacity readings exceeding the opacity standard of 25 Pa. Code Section 123.41 shall be defined as an excursion.

 # 031 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.8]

(a) The permittee shall develop and implement a Quality Improvement Plan (QIP) as expeditiously as practicable if any of the following occur:

(1) Six (6) excursions occur in a six (6) month reporting period.

(2) The Department determines after review of all reported information that the permittee has not responded acceptably to an excursion.

(b) The QIP should be developed within 60 days and the permittee shall provide a copy of the QIP to the Department. Furthermore, the permittee shall notify the Department if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(c) The permittee shall record actions taken to implement a QIP during a reporting period and all related actions including, but not limited to, inspections, repairs, and maintenance performed on the COMS associated with Source ID 031.

(d) In accordance with 40 CFR Section 64.8, the QIP shall include procedures for evaluating the control performance

problems. Based on the results of the evaluation procedures, the permittee shall modify the QIP and provide the Department with a copy, to include procedures for conducting more frequent, or improved, monitoring in conjunction with one or more of the following:

(1) Improved preventive maintenance practices,

(2) Process operation changes,

(3) Appropriate improvements to the control methods,

(4) Other steps appropriate to correct performance.

(e) Following implementation of a QIP, the Department will require reasonable revisions to the QIP if the plan has failed to either:

(1) Address the cause of the performance problems of the COMS associated with Source ID 031.

(2) Provide adequate procedures for correcting the performance problems of the COMS associated with Source ID 031 in as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(f) Implementation of a QIP shall not excuse the permittee from compliance with any existing emission limitation or standard or any existing monitoring, testing, reporting or recordkeeping requirements that may apply under any federal, state, or local laws or any other applicable requirements under the Clean Air Act.

 # 032 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall comply with all applicable requirements of 40 CFR Part 98 Subpart D relating to GHG reporting for Source IDs 031 through 034.

 # 033 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Chapter 145]

Source IDs 031, 032, 033 and 034 are NOx budget units and are subject to 25 Pa. Code Chapter 145, Subchapter A - NOx Budget Trading Program. The permittee shall comply with all applicable requirements specified in 25 Pa. Code Sections 145.1 through 145.100.

 # 034 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Control Device IDs C20 and C21 associated with Source IDs 031 and 032 are considered SNCR system #1, which also consists of a storage tank and a recirculation pump. Control Device IDs C22 and C23 associated with Source IDs 033 & 034 are considered SNCR system #2, which also consists of a storage tank and a recirculation pump.

 # 035 [25 Pa. Code §127.531]

Special conditions related to acid rain.

The permittee shall comply with all applicable requirements and procedures established in regulations promulgated under Title IV of the Clean Air Act, including all applicable provisions from the following:

40 CFR Part 72	Permit Regulation
40 CFR Part 73	Sulfur Dioxide Allowance System
40 CFR Part 75	Continuous Emission Monitoring
40 CFR Part 76	Nitrogen Oxides Emission Reduction Program
40 CFR Part 77	Excess Emissions

Attached to this permit (TVOP 17-00001) is the Phase II Title IV (Acid Rain) permit (TIVOP 17-00001) in its entirety, renewed on May 29, 2009 and effective through December 31, 2012. Certain requirements from the Acid Rain permit have been reiterated in the body of the Title V permit for emphasis. The entire Title IV permit is incorporated into this Title V permit by inclusion.

 # 036 [40 CFR Part 64 Compliance Assurance Monitoring for Major Stationary Sources §40 CFR 64.1]

Sections of PART 64

Definitions

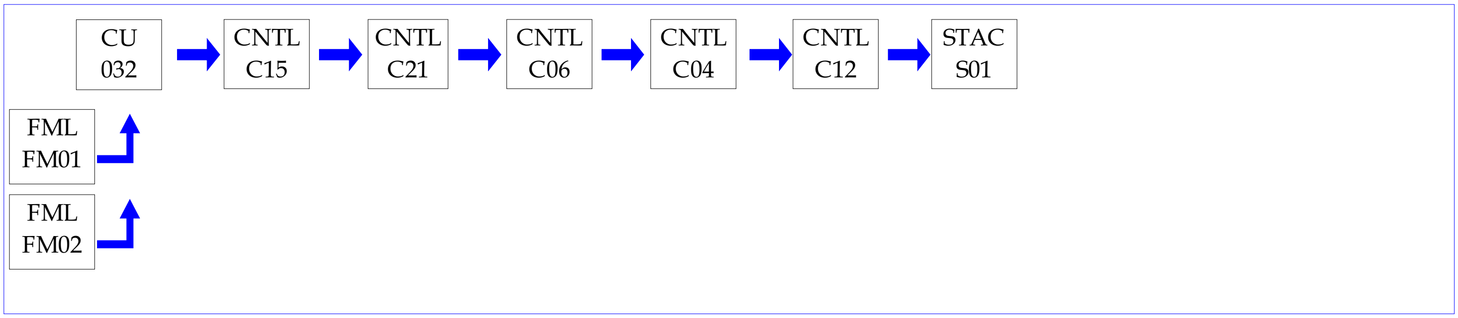
Source ID 031 is subject to the CAM requirements of 40 CFR Part 64. The permittee shall comply with all applicable requirements of 40 CFR Sections 64.1 through 64.10.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 032 Source Name: UTILITY BOILER - UNIT 2

Source Capacity/Throughput: 1,345.000 MMBTU/HR



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.11]

Combustion units

No person may permit the emission into the outdoor atmosphere of particulate matter from the exhaust of Source ID 032 in excess of 0.1 pound per million Btu of heat input.

 # 002 [25 Pa. Code §123.22]

Combustion units

(a) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 032 in excess of the rate of 4 pounds per million Btu of heat input over any 1-hour period when firing #2 fuel oil.

(b) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 032 in excess of the pounds of SO2 per 10^6 Btu heat input as shown below when firing solid fossil fuels:

Thirty-day running average not to be exceeded at any time: 3.7 lbs./10^6 Btu

Daily average not to be exceeded more than 2 days in any running 30-day period: 4.0 lbs./10^6 Btu

Daily average not to be exceeded at any time: 4.8 lbs./10^6 Btu

 # 003 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The ammonia (NH3) emission rate from the exhaust of Source ID 032 shall not exceed 0.003 lbs/MMBTU of heat input.

 # 004 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 through 129.95 and 40 CFR Section 76.5(a)(1)]

The nitrogen oxides emissions (NOx, expressed as NO2) from the exhaust of Source ID 032 shall not exceed 0.542 pounds per million BTU of heat input based on a 30 day rolling average.

 # 005 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The ammonia slip resulting from the operation of each SNCR system associated with Source IDs 031, 032, 033 and 034 shall not exceed 5 ppmv corrected to 8% oxygen.

 # 006 [25 Pa. Code §127.531]

Special conditions related to acid rain.

(a) The permittee shall not emit into the outdoor atmosphere, annual emissions of sulfur dioxide in excess of the number of allowances to emit sulfur dioxide that the permittee or designated representative holds for each affected source.

(b) The permittee shall not emit sulfur dioxide in a manner that would exceed applicable emission rates or standards, including ambient air quality standards.

(c) The permittee shall not use a sulfur dioxide allowance prior to the year for which the allowance is allocated.

(d) A limit will not be placed on the number of sulfur dioxide allowances held for a source. The permittee shall not, however, use allowances as a defense to noncompliance with other applicable requirements.

(e) The permittee shall account for all allowances in accordance with the procedures established in regulations promulgated under Title IV of the Clean Air Act.

 # 007 [40 CFR Part 52 Approval And Promulgation of Implementation Plans §40 CFR 52.2020]

Subpart NN--Pennsylvania

Identification of plan.

No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 032 in excess of the rate of 4 pounds per million Btu of heat input at any time.

Fuel Restriction(s).

 # 008 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 123.22]

The sulfur content of the #2 and lighter fuel oil fired in Source ID 032 shall not exceed 0.5% (by weight).

 # 009 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from RFD condition approved April 8, 2002]

The only binding agents to be used in manufacturing the synthetic fuels used at the Shawville Station shall be soybean oil, Accretion Technologies FTH-100, Nalco 9838, Dow Covol 298 and Dow Covol 298-1 having the compositions identified in the materials submitted with the request for determination dated February 18, 2002 and approved on April 8, 2002. Additionally, the maximum application rate of the soybean oil shall be 1.0% by weight of the soybean oil/coal mixture and the maximum application rate of any of the other four binding agents shall be such that the maximum application rate of the combined non-water constituents contained in the binding agent shall never exceed 1.0% by weight of the binding agent/coal mixture.

II. TESTING REQUIREMENTS.

 # 010 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable testing requirements specified in 25 Pa. Code Chapter 139 and the Departments "Source Testing Manual."

 # 011 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall conduct testing of the SNCR systems between January 1, 2014 and December 31, 2014 and every five years thereafter. The permittee shall conduct the following testing upon the exhaust of the utility boilers:

(a) The ammonia testing shall be conducted upon the exhausts of Source IDs 031 and Source ID 032, respectively, and the common exhaust of Source IDs 033 and 034 using EPA reference method stack testing or an alternative ammonia test method approved by the Department to determine ammonia slip levels and ammonia emissions from each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034.

(b) During the stack testing, the permittee shall measure and, record the gross megawatt load, NOx emissions and SNCR ammonia slip levels for each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034, and such information shall be provided in the stack test report submitted to the Department.

 # 012 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

Between January 1, 2014 and December 31, 2014 and every five years thereafter, the permittee shall perform stack testing on the four utility boilers (Source IDs 031, 032, 033 and 034) to demonstrate compliance with the particulate matter emission limitation contained in this operating permit. Stack testing shall be performed in accordance with the applicable provisions of 25 Pa. Code Chapter 139 (relating to sampling and testing) using test methods and procedures approved by the Department. Testing must be performed while the sources are operating at maximum routine operating conditions.

III. MONITORING REQUIREMENTS.

 # 013 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 123.25, 123.46, 123.51, 40 CFR Part 75, and 40 CFR Sections 64.3 and 64.6]

(a) The permittee shall install, calibrate, maintain and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxide emissions, either oxygen or carbon dioxide concentration and volumetric flow in accordance with all applicable requirements specified in, or established pursuant to: 25 Pa. Code Chapters 123 and 139, the Department's "Continuous Source Monitoring Manual" and 40 CFR Part 75.

(b) All continuous emissions monitoring systems shall be tested in accordance with all applicable requirements specified in 25 Pa. Code Chapter 139, the Departments "Continuous Source Monitoring Manual" and 40 CFR Part 75.

 # 014 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511 and 40 CFR Sections 64.3 and 64.6]

The permittee shall comply with all applicable monitoring requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 015 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall install and maintain instrumentation to monitor and record the ammonia injection rate of the SNCR systems associated with Source IDs 031, 032, 033, and 034 on a continuous basis. Additionally, the permittee shall continuously monitor and record the gross megawatt load and NOx emissions associated with the boilers.

These records shall be retained for a minimum of five years and shall be presented to the Department upon request.

IV. RECORDKEEPING REQUIREMENTS.

 # 016 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable recordkeeping requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 017 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall keep records of the data and calculations used to verify compliance with the particulate matter, sulfur oxides (SOx) and ammonia (NH3) emissions limitations for Source ID 032.

(b) The permittee shall keep records of the tests conducted or certification reports used to verify the sulfur content (percent by weight) of the fuel oil.

These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

 # 018 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

(a) The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95.

(b) The permittee shall keep records, including data which clearly demonstrates that the NOX emission limits for Source ID 032 are met.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

 # 019 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall keep records of the opacity reading from the continuous opacity monitoring system (COMS) associated with Source ID 032.

(b) The permittee shall keep records of all inspections, repairs, and maintenance performed on the COMS associated with Source ID 032.

(c) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 020 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall record all excursions and corrective actions taken in response to an excursion and the time elapsed until the corrective actions have been taken.

(b) The permittee shall keep records of all monitoring downtime incidents associated with the COMS associated with Source ID 032. The permittee shall also record the dates, times and durations, possible causes, and corrective actions taken for the incidents.

(c) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 021 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall keep records of the calculations, including ammonia emissions test reports, used to determine compliance with the SNCR ammonia slip emissions limitations for Source IDs 031, 032, 033 and 034. These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

 # 022 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable reporting requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 023 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9 and Section 70.6(a)(3)(iii)(A)]

(a) The permittee shall submit reports to the Department on a semi-annual basis that include the records of all excursions and corrective actions taken, the dates, times, durations, and possible causes.

(b) The permittee shall submit reports to the Department on a semi-annual basis that include all monitoring downtime incidents, their dates, times and durations, possible causes, and corrective actions taken.

(c) The semi-annual reports shall be submitted to the Department no later than March 1 (for July 1 through December 31 of the previous year) and September 1 (for January 1 through June 30 of the current year).

 # 024 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit permit condition is also derived from 40 CFR Section 98.42]

The permittee shall report the annual mass emissions of CO2, N20, and CH4 from Source IDs 031 through 034 in accordance with the requirements of 40 CFR Part 98 Subpart D.

 # 025 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit permit condition is also derived from 40 CFR Section 98.43]

The permittee shall calculate and report the annual N20 and CH4 mass emissions from Source IDs 031 through 034 by following the applicable method specified in 40 CFR Section 98.33(c).

VI. WORK PRACTICE REQUIREMENTS.

 # 026 [25 Pa. Code §127.441]

Operating permit terms and conditions.

No reclaimed or waste oil or oil that contains any waste material shall be used as fuel in the lighter associated with the low NOX burners of Source ID 032.

 # 027 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 129.91]

The permittee shall maintain and operate Source ID 032 in accordance with the manufacturers specifications. This requirement shall be considered as VOC RACT for Source ID 032.

 # 028 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The SNCR systems (Control Device IDs C20, C21, C22, and C23) shall be operated in accordance with the manufacturer specifications and good air pollution control practices.

VII. ADDITIONAL REQUIREMENTS.

 # 029 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source ID 032 is a 1954 vintage, Babcock Wilcox, dry bottom, front wall-fired, balanced draft, divided furnace drum type utility boiler with a rated heat input capacity of 1,345 MMBtu/hr. The boiler is fueled with pulverized bituminous coal/synfuel or #2 oil. The air contaminant emissions from the subject boiler shall be controlled by 16 Dual Register Low NOX (DRB-XCL) Babcock and Wilcox burners (Control Device ID C15), a NH3/SO3 injection flue gas conditioning system (Control Device ID C06) and a two stage Research Cottrell & Buell electrostatic precipitator (Control Device IDs C04 and C12).

The nitrogen oxides emissions from Source ID 031 may further be controlled by an Energy System Associates selective non-catalytic reduction system (Control Device ID C21).

 # 030 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511 and 40 CFR Sections 64.3 and 64.6]

Any opacity readings exceeding the opacity standard of 25 Pa. Code Section 123.41 shall be defined as an excursion.

 # 031 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.8]

(a) The permittee shall develop and implement a Quality Improvement Plan (QIP) as expeditiously as practicable if any of the following occur:

(1) Six (6) excursions occur in a six (6) month reporting period.

(2) The Department determines after review of all reported information that the permittee has not responded acceptably to an excursion.

(b) The QIP should be developed within 60 days and the permittee shall provide a copy of the QIP to the Department. Furthermore, the permittee shall notify the Department if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(c) The permittee shall record actions taken to implement a QIP during a reporting period and all related actions including, but not limited to, inspections, repairs, and maintenance performed on the COMS associated with Source ID 032.

(d) In accordance with 40 CFR Section 64.8, the QIP shall include procedures for evaluating the control performance problems. Based on the results of the evaluation procedures, the permittee shall modify the QIP and provide the Department with a copy, to include procedures for conducting more frequent, or improved, monitoring in conjunction with one or more of the following:

(1) Improved preventive maintenance practices,

(2) Process operation changes,

(3) Appropriate improvements to the control methods,

(4) Other steps appropriate to correct performance.

(e) Following implementation of a QIP, the Department will require reasonable revisions to the QIP if the plan has failed to either:

(1) Address the cause of the performance problems of the COMS associated with Source ID 032.

(2) Provide adequate procedures for correcting the performance problems of the COMS associated with Source ID 032 in as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(f) Implementation of a QIP shall not excuse the permittee from compliance with any existing emission limitation or standard or any existing monitoring, testing, reporting or recordkeeping requirements that may apply under any federal, state, or local laws or any other applicable requirements under the Clean Air Act.

 # 032 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall comply with all applicable requirements of 40 CFR Part 98 Subpart D relating to GHG reporting for Source IDs 031 through 034.

 # 033 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Chapter 145]

Source IDs 031, 032, 033 and 034 are NOx budget units and are subject to 25 Pa. Code Chapter 145, Subchapter A - NOx Budget Trading Program. The permittee shall comply with all applicable requirements specified in 25 Pa. Code Sections 145.1 through 145.100.

 # 034 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Control Device IDs C20 and C21 associated with Source IDs 031 and 032 are considered SNCR system #1, which also consists of a storage tank and a recirculation pump. Control Device IDs C22 and C23 associated with Source IDs 033 & 034 are considered SNCR system #2, which also consists of a storage tank and a recirculation pump.

 # 035 [25 Pa. Code §127.531]

Special conditions related to acid rain.

The permittee shall comply with all applicable requirements and procedures established in regulations promulgated under Title IV of the Clean Air Act, including all applicable provisions from the following:

40 CFR Part 72	Permit Regulation

40 CFR Part 73	Sulfur Dioxide Allowance System
40 CFR Part 75	Continuous Emission Monitoring
40 CFR Part 76	Nitrogen Oxides Emission Reduction Program
40 CFR Part 77	Excess Emissions

Attached to this permit (TVOP 17-00001) is the Phase II Title IV (Acid Rain) permit (TIVOP 17-00001) in its entirety, renewed on May 29, 2009 and effective through December 31, 2012. Certain requirements from the Acid Rain permit have been reiterated in the body of the Title V permit for emphasis. The entire Title IV permit is incorporated into this Title V permit by inclusion.

 # 036 [40 CFR Part 64 Compliance Assurance Monitoring for Major Stationary Sources §40 CFR 64.1]

Sections of PART 64

Definitions

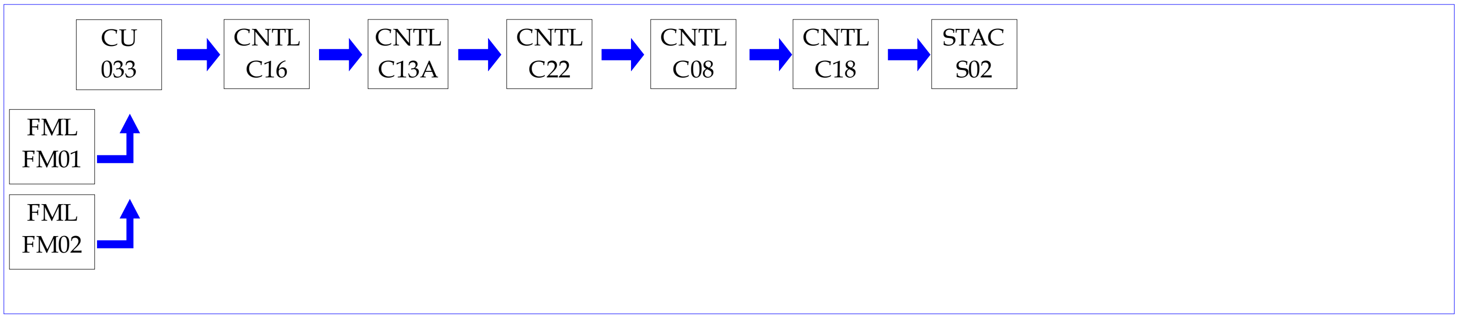
Source ID 032 is subject to the CAM requirements of 40 CFR Part 64. The permittee shall comply with all applicable requirements of 40 CFR Sections 64.1 through 64.10.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 033 Source Name: UTILITY BOILER - UNIT 3

Source Capacity/Throughput: 1,790.000 MMBTU/HR



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.11]

Combustion units

No person may permit the emission into the outdoor atmosphere of particulate matter from the exhaust of Source ID 033 in excess of 0.1 pound per million Btu of heat input.

 # 002 [25 Pa. Code §123.22]

Combustion units

(a) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 033 in excess of the rate of 4 pounds per million Btu of heat input over any 1-hour period when firing #2 fuel oil.

(b) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 033 in excess of the pounds of SO2 per 10^6 Btu heat input as shown below when firing solid fossil fuels:

Thirty-day running average not to be exceeded at any time: 3.7 lbs./10^6 Btu

Daily average not to be exceeded more than 2 days in any running 30-day period: 4.0 lbs./10^6 Btu

Daily average not to be exceeded at any time: 4.8 lbs./10^6 Btu

 # 003 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 through 129.95 and 40 CFR Section 76.5(a)(1)]

The nitrogen oxides emissions (NOx, expressed as NO2) from the exhaust of Source ID 033 shall not exceed 0.45 pounds per million BTU of heat input based on a 30 day rolling average.

 # 004 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The ammonia slip resulting from the operation of each SNCR system associated with Source IDs 031, 032, 033 and 034 shall not exceed 5 ppmv corrected to 8% oxygen.

 # 005 [25 Pa. Code §127.531]

Special conditions related to acid rain.

(a) The permittee shall not emit into the outdoor atmosphere, annual emissions of sulfur dioxide in excess of the number of allowances to emit sulfur dioxide that the permittee or designated representative holds for each affected source.

(b) The permittee shall not emit sulfur dioxide in a manner that would exceed applicable emission rates or standards, including ambient air quality standards.

(c) The permittee shall not use a sulfur dioxide allowance prior to the year for which the allowance is allocated.

(d) A limit will not be placed on the number of sulfur dioxide allowances held for a source. The permittee shall not, however, use allowances as a defense to noncompliance with other applicable requirements.

(e) The permittee shall account for all allowances in accordance with the procedures established in regulations promulgated under Title IV of the Clean Air Act.

 # 006 [40 CFR Part 52 Approval And Promulgation of Implementation Plans §40 CFR 52.2020]

Subpart NN--Pennsylvania

Identification of plan.

No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 033 in excess of the rate of 4 pounds per million Btu of heat input at any time.

Fuel Restriction(s).

 # 007 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 123.22]

The sulfur content of the #2 and lighter fuel oil fired in Source ID 033 shall not exceed 0.5% (by weight).

 # 008 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from RFD condition approved April 8, 2002]

The only binding agents to be used in manufacturing the synthetic fuels used at the Shawville Station shall be soybean oil, Accretion Technologies FTH-100, Nalco 9838, Dow Covol 298 and Dow Covol 298-1 having the compositions identified in the materials submitted with the request for determination dated February 18, 2002 and approved on April 8, 2002. Additionally, the maximum application rate of the soybean oil shall be 1.0% by weight of the soybean oil/coal mixture and the maximum application rate of any of the other four binding agents shall be such that the maximum application rate of the combined non-water constituents contained in the binding agent shall never exceed 1.0% by weight of the binding agent/coal mixture.

II. TESTING REQUIREMENTS.

 # 009 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable testing requirements specified in 25 Pa. Code Chapter 139 and the Departments "Source Testing Manual."

 # 010 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall conduct testing of the SNCR systems between January 1, 2014 and December 31, 2014 and every five years thereafter. The permittee shall conduct the following testing upon the exhaust of the utility boilers:

(a) The ammonia testing shall be conducted upon the exhausts of Source IDs 031 and Source ID 032, respectively, and the common exhaust of Source IDs 033 and 034 using EPA reference method stack testing or an alternative ammonia test method approved by the Department to determine ammonia slip levels and ammonia emissions from each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034.

(b) During the stack testing, the permittee shall measure and, record the gross megawatt load, NOx emissions and SNCR ammonia slip levels for each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034, and such information shall be provided in the stack test report submitted to the Department.

 # 011 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

Between January 1, 2014 and December 31, 2014 and every five years thereafter, the permittee shall perform stack testing on the four utility boilers (Source IDs 031, 032, 033 and 034) to demonstrate compliance with the particulate matter emission limitation contained in this operating permit. Stack testing shall be performed in accordance with the applicable provisions of 25 Pa. Code Chapter 139 (relating to sampling and testing) using test methods and procedures approved by the Department. Testing must be performed while the sources are operating at maximum routine operating conditions.

III. MONITORING REQUIREMENTS.

 # 012 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 123.25, 123.46, 123.51, 40 CFR Part 75, and 40 CFR Sections 64.3 and 64.6]

(a) The permittee shall install, calibrate, maintain and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxide emissions, either oxygen or carbon dioxide concentration and volumetric flow in accordance with all applicable requirements specified in, or established pursuant to: 25 Pa. Code Chapters 123 and 139, the Department's "Continuous Source Monitoring Manual" and 40 CFR Part 75.

(b) All continuous emissions monitoring systems shall be tested in accordance with all applicable requirements specified in 25 Pa. Code Chapter 139, the Departments "Continuous Source Monitoring Manual" and 40 CFR Part 75.

 # 013 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511 and 40 CFR Sections 64.3 and 64.6]

The permittee shall comply with all applicable monitoring requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 014 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall install and maintain instrumentation to monitor and record the ammonia injection rate of the SNCR systems associated with Source IDs 031, 032, 033, and 034 on a continuous basis. Additionally, the permittee shall continuously monitor and record the gross megawatt load and NOx emissions associated with the boilers.

These records shall be retained for a minimum of five years and shall be presented to the Department upon request.

IV. RECORDKEEPING REQUIREMENTS.

 # 015 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable recordkeeping requirements specified in 25 Pa. Code Chapter 139 and the

Departments "Continuous Source Monitoring Manual".

 # 016 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

(a) The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95.

(b) The permittee shall keep records, including data which clearly demonstrates that the NOX emission limits for Source ID 033 are met.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

 # 017 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall keep records of the data and calculations used to verify compliance with the particulate matter and sulfur oxides (SOx) emissions limitations for Source ID 033.

(b) The permittee shall keep records of the tests conducted or certification reports used to verify the sulfur content (percent by weight) of the fuel oil.

These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

 # 018 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall keep records of the opacity reading from the continuous opacity monitoring system (COMS) associated with Source ID 033.

(b) The permittee shall keep records of all inspections, repairs, and maintenance performed on the COMS associated with Source ID 033.

(c) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 019 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall record all excursions and corrective actions taken in response to an excursion and the time elapsed until the corrective actions have been taken.

(b) The permittee shall keep records of all monitoring downtime incidents associated with the COMS associated with Source ID 033. The permittee shall also record the dates, times and durations, possible causes, and corrective actions taken for the incidents.

(c) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 020 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall keep records of the calculations, including ammonia emissions test reports, used to determine compliance with the SNCR ammonia slip emissions limitations for Source IDs 031, 032, 033 and 034. These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

 # 021 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable reporting requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 022 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9 and Section 70.6(a)(3)(iii)(A)]

(a) The permittee shall submit reports to the Department on a semi-annual basis that include the records of all excursions and corrective actions taken, the dates, times, durations, and possible causes.

(b) The permittee shall submit reports to the Department on a semi-annual basis that include all monitoring downtime incidents, their dates, times and durations, possible causes, and corrective actions taken.

(c) The semi-annual reports shall be submitted to the Department no later than March 1 (for July 1 through December 31 of the previous year) and September 1 (for January 1 through June 30 of the current year).

 # 023 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit permit condition is also derived from 40 CFR Section 98.42]

The permittee shall report the annual mass emissions of CO2, N20, and CH4 from Source IDs 031 through 034 in accordance with the requirements of 40 CFR Part 98 Subpart D.

 # 024 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit permit condition is also derived from 40 CFR Section 98.43]

The permittee shall calculate and report the annual N20 and CH4 mass emissions from Source IDs 031 through 034 by following the applicable method specified in 40 CFR Section 98.33(c).

VI. WORK PRACTICE REQUIREMENTS.

 # 025 [25 Pa. Code §127.441]

Operating permit terms and conditions.

No reclaimed or waste oil or oil that contains any waste material shall be used as fuel in the lighter associated with the low NOX burners of Source ID 033.

 # 026 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 129.91]

The permittee shall maintain and operate Source ID 033 in accordance with the manufacturers specifications. This requirement shall be considered as VOC RACT for Source ID 033.

 # 027 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The SNCR systems (Control Device IDs C20, C21, C22, and C23) shall be operated in accordance with the manufacturer specifications and good air pollution control practices.

VII. ADDITIONAL REQUIREMENTS.

 # 028 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Sources ID 033 and 034 (Unit 3 and 4) may be used for the incineration/evaporation of liquid wastes resulting from the chemical cleaning of boiler tubes with non-hazardous (HAP) and non-VOC containing liquid cleaning solutions.

 # 029 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID 033 is a 1959 vintage, Combustion Engineering, tangential fired, balanced draft, divided furnace, with a combined circulation, radiant, reheat boiler with a rated heat input capacity of 1,790 MMBtu/hr. The boiler is fueled with pulverized bituminous coal/synfuel or #2 oil. The air contaminant emissions from the subject boiler shall be controlled by low NOX burners {LNCFSIII} (Control Device ID C16), overfire air (Control Device ID C13A) and a two stage Research Cottrell & Buell electrostatic precipitator (Control Device IDs C08 and C18).

The nitrogen oxides emissions from Source ID 033 may further be controlled by an Energy System Associates selective non-catalytic reduction system (Control Device ID C22).

 # 030 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511 and 40 CFR Sections 64.3 and 64.6]

Any opacity readings exceeding the opacity standard of 25 Pa. Code Section 123.41 shall be defined as an excursion.

 # 031 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.8]

(a) The permittee shall develop and implement a Quality Improvement Plan (QIP) as expeditiously as practicable if any of the following occur:

(1) Six (6) excursions occur in a six (6) month reporting period.

(2) The Department determines after review of all reported information that the permittee has not responded acceptably to an excursion.

(b) The QIP should be developed within 60 days and the permittee shall provide a copy of the QIP to the Department. Furthermore, the permittee shall notify the Department if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(c) The permittee shall record actions taken to implement a QIP during a reporting period and all related actions including, but not limited to, inspections, repairs, and maintenance performed on the COMS associated with Source ID 033.

(d) In accordance with 40 CFR Section 64.8, the QIP shall include procedures for evaluating the control performance problems. Based on the results of the evaluation procedures, the permittee shall modify the QIP and provide the Department with a copy, to include procedures for conducting more frequent, or improved, monitoring in conjunction with one or more of the following:

(1) Improved preventive maintenance practices,

(2) Process operation changes,

(3) Appropriate improvements to the control methods,

(4) Other steps appropriate to correct performance.

(e) Following implementation of a QIP, the Department will require reasonable revisions to the QIP if the plan has failed to either:

(1) Address the cause of the performance problems of the COMS associated with Source ID 033.

(2) Provide adequate procedures for correcting the performance problems of the COMS associated with Source ID 033 in as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(f) Implementation of a QIP shall not excuse the permittee from compliance with any existing emission limitation or standard or any existing monitoring, testing, reporting or recordkeeping requirements that may apply under any federal, state, or local laws or any other applicable requirements under the Clean Air Act.

 # 032 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall comply with all applicable requirements of 40 CFR Part 98 Subpart D relating to GHG reporting for Source IDs 031 through 034.

 # 033 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Chapter 145]

Source IDs 031, 032, 033 and 034 are NOx budget units and are subject to 25 Pa. Code Chapter 145, Subchapter A - NOx Budget Trading Program. The permittee shall comply with all applicable requirements specified in 25 Pa. Code Sections 145.1 through 145.100.

 # 034 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Control Device IDs C20 and C21 associated with Source IDs 031 and 032 are considered SNCR system #1, which also consists of a storage tank and a recirculation pump. Control Device IDs C22 and C23 associated with Source IDs 033 & 034 are considered SNCR system #2, which also consists of a storage tank and a recirculation pump.

 # 035 [25 Pa. Code §127.531]

Special conditions related to acid rain.

The permittee shall comply with all applicable requirements and procedures established in regulations promulgated under Title IV of the Clean Air Act, including all applicable provisions from the following:

40 CFR Part 72	Permit Regulation

40 CFR Part 73	Sulfur Dioxide Allowance System
40 CFR Part 75	Continuous Emission Monitoring
40 CFR Part 76	Nitrogen Oxides Emission Reduction Program
40 CFR Part 77	Excess Emissions

Attached to this permit (TVOP 17-00001) is the Phase II Title IV (Acid Rain) permit (TIVOP 17-00001) in its entirety, renewed on May 29, 2009 and effective through December 31, 2012. Certain requirements from the Acid Rain permit have been reiterated in the body of the Title V permit for emphasis. The entire Title IV permit is incorporated into this Title V permit by inclusion.

 # 036 [40 CFR Part 64 Compliance Assurance Monitoring for Major Stationary Sources §40 CFR 64.1]

Sections of PART 64

Definitions

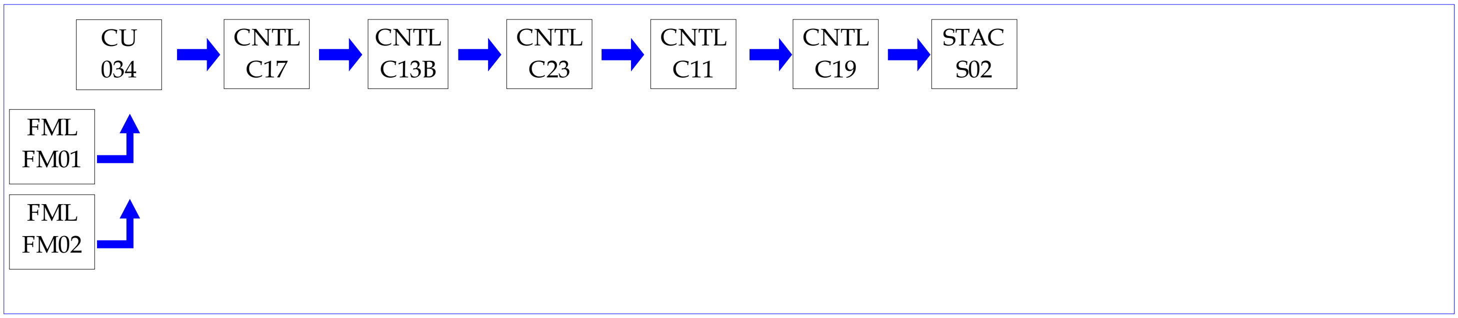
Source ID 033 is subject to the CAM requirements of 40 CFR Part 64. The permittee shall comply with all applicable requirements of 40 CFR Sections 64.1 through 64.10.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 034 Source Name: UTILITY BOILER - UNIT 4

Source Capacity/Throughput: 1,790.000 MMBTU/HR



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.11]

Combustion units

No person may permit the emission into the outdoor atmosphere of particulate matter from the exhaust of Source ID 034 in excess of 0.1 pound per million Btu of heat input.

 # 002 [25 Pa. Code §123.22]

Combustion units

(a) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 034 in excess of the rate of 4 pounds per million Btu of heat input over any 1-hour period when firing #2 fuel oil.

(b) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 034 in excess of the pounds of SO2 per 10^6 Btu heat input as shown below when firing solid fossil fuels:

Thirty-day running average not to be exceeded at any time: 3.7 lbs./10^6 Btu

Daily average not to be exceeded more than 2 days in any running 30-day period: 4.0 lbs./10^6 Btu

Daily average not to be exceeded at any time: 4.8 lbs./10^6 Btu

 # 003 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 through 129.95 and 40 CFR Section 76.5(a)(1)]

The nitrogen oxides emissions (NOx, expressed as NO2) from the exhaust of Source ID 034 shall not exceed 0.45 pounds per million BTU of heat input based on a 30 day rolling average.

 # 004 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The ammonia slip resulting from the operation of each SNCR system associated with Source IDs 031, 032, 033 and 034 shall not exceed 5 ppmv corrected to 8% oxygen.

 # 005 [25 Pa. Code §127.531]

Special conditions related to acid rain.

(a) The permittee shall not emit into the outdoor atmosphere, annual emissions of sulfur dioxide in excess of the number of allowances to emit sulfur dioxide that the permittee or designated representative holds for each affected source.

(b) The permittee shall not emit sulfur dioxide in a manner that would exceed applicable emission rates or standards, including ambient air quality standards.

(c) The permittee shall not use a sulfur dioxide allowance prior to the year for which the allowance is allocated.

(d) A limit will not be placed on the number of sulfur dioxide allowances held for a source. The permittee shall not, however, use allowances as a defense to noncompliance with other applicable requirements.

(e) The permittee shall account for all allowances in accordance with the procedures established in regulations promulgated under Title IV of the Clean Air Act.

 # 006 [40 CFR Part 52 Approval And Promulgation of Implementation Plans §40 CFR 52.2020]

Subpart NN--Pennsylvania

Identification of plan.

No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 034 in excess of the rate of 4 pounds per million Btu of heat input at any time.

Fuel Restriction(s).

 # 007 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 123.22]

The sulfur content of the #2 and lighter fuel oil fired in Source ID 034 shall not exceed 0.5% (by weight).

 # 008 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from RFD condition approved April 8, 2002]

The only binding agents to be used in manufacturing the synthetic fuels used at the Shawville Station shall be soybean oil, Accretion Technologies FTH-100, Nalco 9838, Dow Covol 298 and Dow Covol 298-1 having the compositions identified in the materials submitted with the request for determination dated February 18, 2002 and approved on April 8, 2002. Additionally, the maximum application rate of the soybean oil shall be 1.0% by weight of the soybean oil/coal mixture and the maximum application rate of any of the other four binding agents shall be such that the maximum application rate of the combined non-water constituents contained in the binding agent shall never exceed 1.0% by weight of the binding agent/coal mixture.

II. TESTING REQUIREMENTS.

 # 009 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable testing requirements specified in 25 Pa. Code Chapter 139 and the Departments "Source Testing Manual."

 # 010 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall conduct testing of the SNCR systems between January 1, 2014 and December 31, 2014 and every five years thereafter. The permittee shall conduct the following testing upon the exhaust of the utility boilers:

(a) The ammonia testing shall be conducted upon the exhausts of Source IDs 031 and Source ID 032, respectively, and the common exhaust of Source IDs 033 and 034 using EPA reference method stack testing or an alternative ammonia test method approved by the Department to determine ammonia slip levels and ammonia emissions from each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034.

(b) During the stack testing, the permittee shall measure and, record the gross megawatt load, NOx emissions and SNCR ammonia slip levels for each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034, and such information shall be provided in the stack test report submitted to the Department.

 # 011 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

Between January 1, 2014 and December 31, 2014 and every five years thereafter, the permittee shall perform stack testing on the four utility boilers (Source IDs 031, 032, 033 and 034) to demonstrate compliance with the particulate matter emission limitation contained in this operating permit. Stack testing shall be performed in accordance with the applicable provisions of 25 Pa. Code Chapter 139 (relating to sampling and testing) using test methods and procedures approved by the Department. Testing must be performed while the sources are operating at maximum routine operating conditions.

III. MONITORING REQUIREMENTS.

 # 012 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 123.25, 123.46, 123.51, 40 CFR Part 75, and 40 CFR Sections 64.3 and 64.6]

(a) The permittee shall install, calibrate, maintain and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxide emissions, either oxygen or carbon dioxide concentration and volumetric flow in accordance with all applicable requirements specified in, or established pursuant to: 25 Pa. Code Chapters 123 and 139, the Department's "Continuous Source Monitoring Manual" and 40 CFR Part 75.

(b) All continuous emissions monitoring systems shall be tested in accordance with all applicable requirements specified in 25 Pa. Code Chapter 139, the Departments "Continuous Source Monitoring Manual" and 40 CFR Part 75.

 # 013 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511 and 40 CFR Sections 64.3 and 64.6]

The permittee shall comply with all applicable monitoring requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 014 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall install and maintain instrumentation to monitor and record the ammonia injection rate of the SNCR systems associated with Source IDs 031, 032, 033, and 034 on a continuous basis. Additionally, the permittee shall continuously monitor and record the gross megawatt load and NOx emissions associated with the boilers.

These records shall be retained for a minimum of five years and shall be presented to the Department upon request.

IV. RECORDKEEPING REQUIREMENTS.

 # 015 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable recordkeeping requirements specified in 25 Pa. Code Chapter 139 and the

Departments "Continuous Source Monitoring Manual".

 # 016 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

(a) The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95.

(b) The permittee shall keep records, including data which clearly demonstrates that the NOX emission limits for Source ID 034 are met.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

 # 017 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall keep records of the data and calculations used to verify compliance with the particulate matter and sulfur oxides (SOx) emissions limitations for Source ID 034.

(b) The permittee shall keep records of the tests conducted or certification reports used to verify the sulfur content (percent by weight) of the fuel oil.

These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

 # 018 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall keep records of the opacity reading from the continuous opacity monitoring system (COMS) associated with Source ID 034.

(b) The permittee shall keep records of all inspections, repairs, and maintenance performed on the COMS associated with Source ID 034.

(c) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 019 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall record all excursions and corrective actions taken in response to an excursion and the time elapsed until the corrective actions have been taken.

(b) The permittee shall keep records of all monitoring downtime incidents associated with the COMS associated with Source ID 034. The permittee shall also record the dates, times and durations, possible causes, and corrective actions taken for the incidents.

(c) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 020 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall keep records of the calculations, including ammonia emissions test reports, used to determine compliance with the SNCR ammonia slip emissions limitations for Source IDs 031, 032, 033 and 034. These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

 # 021 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable reporting requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 022 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9 and Section 70.6(a)(3)(iii)(A)]

(a) The permittee shall submit reports to the Department on a semi-annual basis that include the records of all excursions and corrective actions taken, the dates, times, durations, and possible causes.

(b) The permittee shall submit reports to the Department on a semi-annual basis that include all monitoring downtime incidents, their dates, times and durations, possible causes, and corrective actions taken.

(c) The semi-annual reports shall be submitted to the Department no later than March 1 (for July 1 through December 31 of the previous year) and September 1 (for January 1 through June 30 of the current year).

 # 023 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit permit condition is also derived from 40 CFR Section 98.42]

The permittee shall report the annual mass emissions of CO2, N20, and CH4 from Source IDs 031 through 034 in accordance with the requirements of 40 CFR Part 98 Subpart D.

 # 024 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit permit condition is also derived from 40 CFR Section 98.43]

The permittee shall calculate and report the annual N20 and CH4 mass emissions from Source IDs 031 through 034 by following the applicable method specified in 40 CFR Section 98.33(c).

VI. WORK PRACTICE REQUIREMENTS.

 # 025 [25 Pa. Code §127.441]

Operating permit terms and conditions.

No reclaimed or waste oil or oil that contains any waste material shall be used as fuel in the lighter associated with the low NOX burners of Source ID 034.

 # 026 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 129.91]

The permittee shall maintain and operate Source ID 034 in accordance with the manufacturers specifications. This requirement shall be considered as VOC RACT for Source ID 034.

 # 027 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The SNCR systems (Control Device IDs C20, C21, C22, and C23) shall be operated in accordance with the manufacturer specifications and good air pollution control practices.

VII. ADDITIONAL REQUIREMENTS.

 # 028 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Sources ID 033 and 034 (Unit 3 and 4) may be used for the incineration/evaporation of liquid wastes resulting from the chemical cleaning of boiler tubes with non-hazardous (HAP) and non-VOC containing liquid cleaning solutions.

 # 029 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID 034 is a 1960 vintage, Combustion Engineering, tangential fired, balanced draft, divided furnace, with a combined circulation, radiant, reheat boiler with a rated heat input capacity of 1,790 MMBtu/hr. The boiler is fueled with pulverized bituminous coal/synfuel or #2 oil. The air contaminant emissions from the subject boiler shall be controlled by low NOX burners {LNCFSIII} (Control Device ID C17), overfire air (Control Device ID C13B) and a two stage Research Cottrell & Buell electrostatic precipitator (Control Device IDs C11 and C19).

The nitrogen oxides emissions from Source ID 034 may further be controlled by an Energy System Associates selective non-catalytic reduction system (Control Device ID C23).

 # 030 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511 and 40 CFR Sections 64.3 and 64.6]

Any opacity readings exceeding the opacity standard of 25 Pa. Code Section 123.41 shall be defined as an excursion.

 # 031 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.8]

(a) The permittee shall develop and implement a Quality Improvement Plan (QIP) as expeditiously as practicable if any of the following occur:

(1) Six (6) excursions occur in a six (6) month reporting period.

(2) The Department determines after review of all reported information that the permittee has not responded acceptably to an excursion.

(b) The QIP should be developed within 60 days and the permittee shall provide a copy of the QIP to the Department. Furthermore, the permittee shall notify the Department if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(c) The permittee shall record actions taken to implement a QIP during a reporting period and all related actions including, but not limited to, inspections, repairs, and maintenance performed on the COMS associated with Source ID 034.

(d) In accordance with 40 CFR Section 64.8, the QIP shall include procedures for evaluating the control performance problems. Based on the results of the evaluation procedures, the permittee shall modify the QIP and provide the Department with a copy, to include procedures for conducting more frequent, or improved, monitoring in conjunction with one or more of the following:

(1) Improved preventive maintenance practices,

(2) Process operation changes,

(3) Appropriate improvements to the control methods,

(4) Other steps appropriate to correct performance.

(e) Following implementation of a QIP, the Department will require reasonable revisions to the QIP if the plan has failed to either:

(1) Address the cause of the performance problems of the COMS associated with Source ID 034.

(2) Provide adequate procedures for correcting the performance problems of the COMS associated with Source ID 034 in as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(f) Implementation of a QIP shall not excuse the permittee from compliance with any existing emission limitation or standard or any existing monitoring, testing, reporting or recordkeeping requirements that may apply under any federal, state, or local laws or any other applicable requirements under the Clean Air Act.

 # 032 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall comply with all applicable requirements of 40 CFR Part 98 Subpart D relating to GHG reporting for Source IDs 031 through 034.

 # 033 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Chapter 145]

Source IDs 031, 032, 033 and 034 are NOx budget units and are subject to 25 Pa. Code Chapter 145, Subchapter A - NOx Budget Trading Program. The permittee shall comply with all applicable requirements specified in 25 Pa. Code Sections 145.1 through 145.100.

 # 034 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Control Device IDs C20 and C21 associated with Source IDs 031 and 032 are considered SNCR system #1, which also consists of a storage tank and a recirculation pump. Control Device IDs C22 and C23 associated with Source IDs 033 & 034 are considered SNCR system #2, which also consists of a storage tank and a recirculation pump.

 # 035 [25 Pa. Code §127.531]

Special conditions related to acid rain.

The permittee shall comply with all applicable requirements and procedures established in regulations promulgated under Title IV of the Clean Air Act, including all applicable provisions from the following:

40 CFR Part 72 Permit Regulation

40 CFR Part 73	Sulfur Dioxide Allowance System
40 CFR Part 75	Continuous Emission Monitoring
40 CFR Part 76	Nitrogen Oxides Emission Reduction Program
40 CFR Part 77	Excess Emissions

Attached to this permit (TVOP 17-00001) is the Phase II Title IV (Acid Rain) permit (TIVOP 17-00001) in its entirety, renewed on May 29, 2009 and effective through December 31, 2012. Certain requirements from the Acid Rain permit have been reiterated in the body of the Title V permit for emphasis. The entire Title IV permit is incorporated into this Title V permit by inclusion.

 # 036 [40 CFR Part 64 Compliance Assurance Monitoring for Major Stationary Sources §40 CFR 64.1]

Sections of PART 64

Definitions

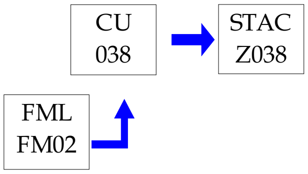
Source ID 034 is subject to the CAM requirements of 40 CFR Part 64. The permittee shall comply with all applicable requirements of 40 CFR Sections 64.1 through 64.10.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 038 Source Name: 15 SPACE HEATERS

Source Capacity/Throughput:



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.13]

Processes

No person shall permit the emission of particulate matter from the exhaust of each space heater into the outdoor atmosphere in a manner that the concentration of particulate matter in the effluent gas exceeds 0.04 grain per dry standard cubic foot.

 # 002 [25 Pa. Code §123.21]

General

No person may permit the emission from the exhaust of each space heater into the outdoor atmosphere in a manner that the concentration of the sulfur oxides (SOX), expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, dry basis.

Fuel Restriction(s).

 # 003 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall only fire #2 or lighter fuel oil in each space heater of Source ID 038.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

 # 004 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall maintain and operate each space heater of Source ID 038 in accordance with manufacturers specifications.

VII. ADDITIONAL REQUIREMENTS.

 # 005 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID 038 consists of fifteen #1 and #2 fuel-oil fired space heaters.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: CAIR Source Name: CAIR CONDITIONS

Source Capacity/Throughput:

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §145.201.]

Purpose.

The permittee and the CAIR designated representative for Source IDs 031, 032, 033, and 034 are subject to 25 Pa. Code Chapter 145, Subchapter D. The permittee and the CAIR designated representative for Source IDs 031, 032, 033, and 034 shall comply with all the applicable requirements specified in 25 Pa. Code Sections 145.201 through 145.223.

 # 002 [25 Pa. Code §145.201.]

Purpose.

In addition to the Federal requirements in the previous sections of this application, all units that meet the applicability requirements in 25 Pa Code Section 145.203 shall meet any applicable requirement of 25 Pa Code Sections 145.204, 145.205, 145.212,145.213, 145.221, 145.222, and 145.223.

 # 003 [25 Pa. Code §145.204.]

Incorporation of Federal regulations by reference.

[Additional authority for this permit condition is derived from 40 CFR Section 96.106]

(a) Permit requirements. (1) The CAIR designated representative of each CAIR NOXsource required to have a title V operating permit and each CAIR NOXunit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under §96.122 in accordance with the deadlines specified in §96.121; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR NOXsource required to have a title V operating permit and each CAIR NOXunit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart II of this part, the owners and operators of a CAIR NOXsource that is not otherwise required to have a title V operating permit and each CAIR NOXunit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CC of this part for such CAIR NOXsource and such CAIR NOXunit.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR NOXsource and each CAIR NOXunit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HH of this part.

(2) The emissions measurements recorded and reported in accordance with subpart HH of this part shall be used to determine compliance by each CAIR NOXsource with the CAIR NOXemissions limitation under paragraph (c) of this section.

(c) Nitrogen oxides emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NOXsource and each CAIR NOXunit at the source shall hold, in the source's compliance account, CAIR NOXallowances available for compliance deductions for the control period under §96.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NOXunits at the source, as determined in accordance with subpart HH of this part.

(2) A CAIR NOXunit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §96.170(b)(1), (2), or (5) and for each control period thereafter.

(3) A CAIR NOXallowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NOXallowance was allocated.

(4) CAIR NOXallowances shall be held in, deducted from, or transferred into or among CAIR NOXAllowance Tracking System accounts in accordance with subparts EE, FF, GG, and II of this part.

(5) A CAIR NOXallowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NOXAnnual Trading Program. No provision of the CAIR NOXAnnual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.105 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(6) A CAIR NOXallowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart EE, FF, GG, or II of this part, every allocation, transfer, or deduction of a CAIR NOXallowance to or from a CAIR NOXsource's compliance account is incorporated automatically in any CAIR permit of the source.

(d) Excess emissions requirements. If a CAIR NOXsource emits nitrogen oxides during any control period in excess of the CAIR NOXemissions limitation, then:

(1) The owners and operators of the source and each CAIR NOXunit at the source shall surrender the CAIR NOXallowances required for deduction under §96.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy

imposed, for the same violations, under the Clean Air Act or applicable State law; and

(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR NOXsource and each CAIR NOXunit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under §96.113 for the CAIR designated representative for the source and each CAIR NOXunit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §96.113 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subpart HH of this part, provided that to the extent that subpart HH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NOXAnnual Trading Program.

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NOXAnnual Trading Program or to demonstrate compliance with the requirements of the CAIR NOXAnnual Trading Program.

(2) The CAIR designated representative of a CAIR NOXsource and each CAIR NOXunit at the source shall submit the reports required under the CAIR NOXAnnual Trading Program, including those under subpart HH of this part.

(f) Liability. (1) Each CAIR NOXsource and each CAIR NOXunit shall meet the requirements of the CAIR NOXAnnual Trading Program.

(2) Any provision of the CAIR NOXAnnual Trading Program that applies to a CAIR NOXsource or the CAIR designated representative of a CAIR NOXsource shall also apply to the owners and operators of such source and of the CAIR NOXunits at the source.

(3) Any provision of the CAIR NOXAnnual Trading Program that applies to a CAIR NOXunit or the CAIR designated representative of a CAIR NOXunit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the CAIR NOXAnnual Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §96.105 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NOXsource or CAIR NOXunit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

 # 004 [25 Pa. Code §145.204.]

Incorporation of Federal regulations by reference.

[Additional authority for this permit condition is derived from 40 CFR Section 96.206]

(a) Permit requirements. (1) The CAIR designated representative of each CAIR SO2source required to have a title V operating permit and each CAIR SO2unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under §96.222 in accordance with the deadlines specified in §96.221; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR SO2source required to have a title V operating permit and each CAIR SO2unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart III of this part, the owners and operators of a CAIR SO2source that is not otherwise required to have a title V operating permit and each CAIR SO2unit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CCC of this part for such CAIR SO2source and such CAIR SO2unit.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR SO2source and each CAIR SO2unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHH of this part.

(2) The emissions measurements recorded and reported in accordance with subpart HHH of this part shall be used to determine compliance by each CAIR SO2source with the CAIR SO2emissions limitation under paragraph (c) of this section.

(c) Sulfur dioxide emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO2source and each CAIR SO2unit at the source shall hold, in the source's compliance account, a tonnage equivalent in CAIR SO2allowances available for compliance deductions for the control period, as determined in accordance with §96.254(a) and (b), not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO2units at the source, as determined in accordance with subpart HHH of this part.

(2) A CAIR SO2unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2010 or the deadline for meeting the unit(s monitor certification requirements under §96.270(b)(1),(2), or (5) and for each control period thereafter.
(3) A CAIR SO2allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR SO2allowance was allocated.

(4) CAIR SO2allowances shall be held in, deducted from, or transferred into or among CAIR SO2Allowance Tracking System accounts in accordance with subparts FFF, GGG, and III of this part.

(5) A CAIR SO2allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO2Trading Program. No provision of the CAIR SO2Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.205 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(6) A CAIR SO2allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart FFF, GGG, or III of this part, every allocation, transfer, or deduction of a CAIR SO2allowance to or from a CAIR SO2source's compliance account is incorporated automatically in any CAIR permit of the source.

(d) Excess emissions requirements. If a CAIR SO2source emits sulfur dioxide during any control period in excess of the CAIR SO2emissions limitation, then:

(1) The owners and operators of the source and each CAIR SO2unit at the source shall surrender the CAIR SO2allowances required for deduction under §96.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy

imposed, for the same violations, under the Clean Air Act or applicable State law; and

(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR SO2source and each CAIR SO2unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under §96.213 for the CAIR designated representative for the source and each CAIR SO2unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §96.213 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subpart HHH of this part, provided that to the extent that subpart HHH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR SO2Trading Program.

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR SO2Trading Program or to demonstrate compliance with the requirements of the CAIR SO2Trading Program.

(2) The CAIR designated representative of a CAIR SO2source and each CAIR SO2unit at the source shall submit the reports required under the CAIR SO2Trading Program, including those under subpart HHH of this part.

(f) Liability. (1) Each CAIR SO2source and each CAIR SO2unit shall meet the requirements of the CAIR SO2Trading Program.

(2) Any provision of the CAIR SO2Trading Program that applies to a CAIR SO2source or the CAIR designated representative of a CAIR SO2source shall also apply to the owners and operators of such source and of the CAIR SO2units at the source.

(3) Any provision of the CAIR SO2Trading Program that applies to a CAIR SO2unit or the CAIR designated representative of a CAIR SO2unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the CAIR SO2Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §96.205 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR SO2source or CAIR SO2unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

 # 005 [25 Pa. Code §145.204.]

Incorporation of Federal regulations by reference.

[Additional authority for this permit condition is derived from 40 CFR Section 96.306]

(a) Permit requirements. (1) The CAIR designated representative of each CAIR NOXOzone Season source required to have a title V operating permit and each CAIR NOXOzone Season unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under §96.322 in accordance with the deadlines specified in §96.321; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.
(2) The owners and operators of each CAIR NOXOzone Season source required to have a title V operating permit and each CAIR NOXOzone Season unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart IIII of this part, the owners and operators of a CAIR NOXOzone Season source that is not otherwise required to have a title V operating permit and each CAIR NOXOzone Season unit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CCCC of this part for such CAIR NOXOzone Season source and such CAIR NOXOzone Season unit.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of this part.

(2) The emissions measurements recorded and reported in accordance with subpart HHHH of this part shall be used to determine compliance by each CAIR NOXOzone Season source with the CAIR NOXOzone Season emissions limitation under paragraph (c) of this section.

(c) Nitrogen oxides ozone season emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall hold, in the source's compliance account, CAIR NOXOzone Season allowances available for compliance deductions for the control period under §96.354(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NOXOzone Season units at the source, as determined in accordance with subpart HHHH of this part.

(2) A CAIR NOXOzone Season unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §96.370(b)(1), (2), (3), or (7) and for each control period thereafter.

(3) A CAIR NOXOzone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NOXOzone Season allowance was allocated.

(4) CAIR NOXOzone Season allowances shall be held in, deducted from, or transferred into or among CAIR NOXOzone Season Allowance Tracking System accounts in accordance with subparts EEEE, FFFF, GGGG, and IIII of this part.

(5) A CAIR NOXOzone Season allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NOXOzone Season Trading Program. No provision of the CAIR NOXOzone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.305 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(6) A CAIR NOXOzone Season allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart EEEE, FFFF, GGGG, or IIII of this part, every allocation, transfer, or deduction of a CAIR NOXOzone Season allowance to or from a CAIR NOXOzone Season source's compliance account is incorporated automatically in any CAIR permit of the source.

(d) Excess emissions requirements. If a CAIR NOXOzone Season source emits nitrogen oxides during any control period in excess of the CAIR NOXOzone Season emissions limitation, then:

(1) The owners and operators of the source and each CAIR NOXOzone Season unit at the source shall surrender the CAIR

NOXOzone Season allowances required for deduction under §96.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under §96.313 for the CAIR designated representative for the source and each CAIR NOXOzone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §96.313 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subpart HHHH of this part, provided that to the extent that subpart HHHH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NOXOzone Season Trading Program.

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NOXOzone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NOXOzone Season Trading Program.

(2) The CAIR designated representative of a CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall submit the reports required under the CAIR NOXOzone Season Trading Program, including those under subpart HHHH of this part.

(f) Liability. (1) Each CAIR NOXOzone Season source and each CAIR NOXOzone Season unit shall meet the requirements of the CAIR NOXOzone Season Trading Program.

(2) Any provision of the CAIR NOXOzone Season Trading Program that applies to a CAIR NOXOzone Season source or the CAIR designated representative of a CAIR NOXOzone Season source shall also apply to the owners and operators of such source and of the CAIR NOXOzone Season units at the source.

(3) Any provision of the CAIR NOXOzone Season Trading Program that applies to a CAIR NOXOzone Season unit or the CAIR designated representative of a CAIR NOXOzone Season unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the CAIR NOXOzone Season Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §96.305 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NOXOzone Season source or CAIR NOXOzone Season unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

 # 006 [25 Pa. Code §145.204.]

Incorporation of Federal regulations by reference.

(a) Except as otherwise specified in this subchapter, the provisions of the CAIR NOx Annual Trading Program, found in 40 CFR Part 96 (relating to NOx budget trading program and CAIR NOx and SO2 trading programs for State implementation plans), including all appendices, future amendments and supplements thereto, are incorporated by reference.

(b) Except as otherwise specified in this subchapter, the provisions of the CAIR SO2 Trading Program, found in 40 CFR Part 96, including all appendices, future amendments and supplements thereto, are incorporated by reference.

(c) Except as otherwise specified in this subchapter, the provisions of the CAIR NOx Ozone Season Trading Program, found in 40 CFR Part 96, including all appendices, future amendments and supplements thereto, are incorporated by reference.

(d) In the event of a conflict between Federal regulatory provisions incorporated by reference in this subchapter and Pennsylvania regulatory provisions, the provision expressly set out in this subchapter shall be followed unless the Federal provision is more stringent. Federal regulations that are cited in this subchapter or that are cross-referenced in the Federal regulations incorporated by reference include any Pennsylvania modifications made to those Federal regulations.

 # 007 [25 Pa. Code §145.205.]

Emission reduction credit provisions.

The following conditions shall be satisfied in order for the Department to issue a permit or plan approval to the owner or operator of a unit not subject to this subchapter that is relying on emission reduction credits (ERCs) or creditable emission reductions in an applicability determination under Chapter 127, Subchapter E (relating to new source review), or is seeking to enter into an emissions trade authorized under Chapter 127 (relating to construction, modification, reactivation and operation of sources), if the ERCs or creditable emission reductions were, or will be, generated by a unit subject to this subchapter.

(1) Prior to issuing the permit or plan approval, the Department will permanently reduce the Commonwealth¿s CAIR NOx trading budget or CAIR NOx Ozone Season trading budget, or both, as applicable, beginning with the sixth control period following the date the plan approval or permit to commence operations or increase emissions is issued. The Department will permanently reduce the applicable CAIR NOx budgets by an amount of allowances equal to the ERCs or creditable emission reductions relied upon in the applicability determination for the non-CAIR unit subject to Chapter 127, Subchapter E or in the amount equal to the emissions trade authorized under Chapter 127, as if these emissions had already been emitted.

(2) The permit or plan approval must prohibit the owner or operator from commencing operation or increasing emissions until the owner or operator of the CAIR unit generating the ERC or creditable emission reduction surrenders to the Department an amount of allowances equal to the ERCs or emission reduction credits relied upon in the applicability determination for the non-CAIR unit under Chapter 127, Subchapter E or the amount equal to the ERC trade authorized under Chapter 127, for each of the five consecutive control periods following the date the non-CAIR unit commences operation or increases emissions. The allowances surrendered must be of present or past vintage years.

 # 008 [25 Pa. Code §145.212.]

CAIR NOx allowance allocations.

(a) Provisions not incorporated by reference. The requirements of 40 CFR 96.142 (relating to CAIR NOx allowance allocations) are not incorporated by reference. Instead of 40 CFR 96.142, the requirements set forth in this section apply.

(b) Baseline heat input. Baseline heat input for each CAIR NOx unit will be converted as follows:

(1) A unit¿s control period heat input and a unit¿s status as coal-fired or oil-fired for a calendar year under this paragraph will be determined in one of the following two ways:

(i) In accordance with 40 CFR Part 75 (relating to continuous emission monitoring), to the extent that the unit was otherwise subject to 40 CFR Part 75 for the year.

(ii) Based on the best available data reported to the Department for the unit, to the extent the unit was not otherwise subject to the requirements of 40 CFR Part 75 for the year.

(2) Except as provided in subparagraphs (iv) and (v), a unit¿s converted control period heat input for a calendar year shall be

determined as follows:

(i) The control period gross electrical output of the generators served by the unit multiplied by 7,900 Btu/kWh if the unit is coal-fired for the year, and divided by 1,000,000 Btu/mmBtu.

(ii) The control period gross electrical output of the generators served by the unit multiplied by 6,675 Btu/kWh if the unit is not coal-fired for the year, and divided by 1,000,000 Btu/mmBtu.

(iii) If a generator is served by two or more units, the gross electrical output of the generator will be attributed to each unit in proportion to the share of the total control period heat input from each of the units for the year.

(iv) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating or cooling purposes through the sequential use of energy, the total heat energy (in Btus) of the steam produced by the boiler during the annual control period, divided by 0.8 and by 1,000,000 Btu/mmBtu.

(v) For a unit that is a combustion turbine and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating or cooling purposes through the sequential use of energy, the annual control period gross electrical output of the enclosed device comprising the compressor, combustor and turbine multiplied by 3,413 Btu/kWh, plus the total heat energy (in Btu) of the steam produced by any associated heat recovery steam generator during the annual control period divided by 0.8, and with the sum divided by 1,000,000 Btu/mmBtu.

(vi) Calculations will be based on the best output data available on or before January 31 of the year the allocations are published. If unit level electrical or steam output data are not available from EIA, or submitted by this date by the owner or operator of the CAIR NOx unit, then heat input data for the period multiplied by 0.25 and converted to MWh will be used to determine total output.

(c) Existing unit, new unit and subsection (f)(1) qualifying resource allocation baseline. For each control period beginning with January 1, 2010, and each year thereafter, the Department will allocate to qualifying resources and CAIR NOx units, including CAIR NOx units issued allowances under subsection (e), a total amount of CAIR NOx allowances equal to the number of CAIR NOx allowances remaining in the Commonwealth¿s CAIR NOx trading budget under 40 CFR 96.140 (relating to State trading budgets) for those control periods using summed baseline heat input data as determined under subsections (b) and (f)(1) from a baseline year that is 6 calendar years before the control period.

(d) Proration of allowance allocations. The Department will allocate CAIR NOx allowances to each existing CAIR NOx unit and qualifying resource in an amount determined by multiplying the amount of CAIR NOx allowances in the Commonwealth¿s CAIR NOx trading budget available for allocation under subsection (c) by the ratio of the baseline heat input of the existing CAIR NOx unit or qualifying resource to the sum of the baseline heat input of existing CAIR NOx units and of the qualifying resources, rounding to the nearest whole allowance as appropriate.

(e) Allocations to new CAIR NOx units. By March 31, 2011, and March 31 each year thereafter, the Department will allocate CAIR NOx allowances under § 145.211(c) (relating to timing requirements for CAIR NOx allowance allocations) to CAIR NOx units equal to the previous year¿s emissions at each unit, unless the unit has been issued allowances of the previous year¿s vintage in a regular allocation under § 145.211(b). The Department will allocate CAIR NOx allowances under this subsection of a vintage year that is 5 years later than the year in which the emissions were generated. The number of CAIR NOx allowances allocated may not exceed the actual emission of the year preceding the year in which the Department makes the allocation. The allocation of these allowances to the new unit will not reduce the number of allowances the unit is entitled to receive under another provision of this subchapter.

(f) Allocations to qualifying resources and units exempted by section 405(g)(6)(a) of the Clean Air Act. For each control period beginning with 2010 and thereafter, the Department will allocate CAIR NOx allowances to qualifying resources under paragraph (1) in this Commonwealth that are not also allocated CAIR NOx allowances under another provision of this subchapter and to existing units under paragraph (2) that were exempted at any time under section 405(g)(6)(a) of the

Clean Air Act (42 U.S.C.A. § 7651d(g)(6)(A)), regarding phase II SO2 requirements, and that commenced operation prior to January 1, 2000, but did not receive an allocation of SO2 allowances under the EPA¿s Acid Rain Program, as follows:

(1) The Department will allocate CAIR NOx allowances to a renewable energy qualifying resource or demand side management energy efficiency qualifying resource in accordance with subsections (c) and (d) upon receipt by the Department of an application, in writing, on or before June 30 of the year following the control period, except for vintage year 2011 and 2012 NOx allowance allocations whose application deadline will be prescribed by the Department, meeting the requirements of this paragraph. The number of allowances allocated to the qualifying resource will be determined by converting the certified quantity of electric energy production, useful thermal energy, and energy equivalent value of the measures approved under the Pennsylvania Alternative Energy Portfolio Standard to equivalent thermal energy. Equivalent thermal energy is a unit¿s baseline heat input for allocation purposes. The conversion rate for converting electrical energy to equivalent thermal energy is 3,413 Btu/kWh. To receive allowances under this subsection, the qualifying resource must have commenced operation after January 1, 2005, must be located in this Commonwealth and may not be a CAIR NOx unit. The following procedures apply:

(i) The owner of a qualifying renewable energy resource shall appoint a CAIR-authorized account representative and file a certificate of representation with the EPA and the Department.

(ii) The Department will transfer the allowances into an account designated by the owner¿s CAIR-authorized account representative of the qualifying resource, or into an account designated by an aggregator approved by the Pennsylvania Public Utility Commission or its designee.

(iii) The applicant shall provide the Department with the corresponding renewable energy certificate serial numbers.

(iv) At least one whole allowance must be generated per owner, operator or aggregator for an allowance to be issued.

(2) The Department will allocate CAIR NOx allowances to the owner or operator of a CAIR SO2 unit that commenced operation prior to January 1, 2000, that has not received an SO2 allocation for that compliance period, as follows:

(i) By January 31, 2011, and each year thereafter, the owner or operator of a unit may apply, in writing, to the Department under this subsection to receive extra CAIR NOx allowances.

(ii) The owner or operator may request under this subparagraph one CAIR NOx allowance for every 8 tons of SO2 emitted from a qualifying unit during the preceding control period. An owner or operator of a unit covered under this subparagraph that has opted into the Acid Rain Program may request one CAIR NOx allowance for every 8 tons of SO2 emissions that have not been covered by the SO2 allowances received as a result of opting into the Acid Rain Program.

(iii) If the original CAIR NOx allowance allocation for the unit for the control period exceeded the unit¿s actual emissions of NOx for the control period, the owner or operator shall also deduct the excess CAIR NOx allowances from the unit¿s request under subparagraph (ii). This amount is the unit¿s adjusted allocation and will be allocated unless the proration described in subparagraph (iv) applies.

(iv) The Department will make any necessary corrections and then sum the requests. If the total number of NOx allowances requested by all qualified units under this paragraph, as adjusted by subparagraph (iii), is less than 1.3% of the Commonwealth¿s CAIR NOx Trading Budget, the Department will allocate the corrected amounts. If the total number of NOx allowances requested by all qualified units under this paragraph exceeds 1.3% of the Commonwealth¿s CAIR NOx Trading Budget, the Department will prorate the allocations based upon the following equation:

AA = [EA X (0.013 X BNA)] / TRA

where,
AA is the unit¿s prorated allocation,

EA is the adjusted allocation the unit may request under subparagraph (iii),
BNA is the total number of CAIR NOx allowances in the Commonwealth¿s CAIR NOx trading budget,
TRA is the total number of CAIR NOx allowances requested by all units requesting allowances under this paragraph.

(3) The Department will review each CAIR NOx allowance allocation request under this subsection and will allocate CAIR NOx allowances for each control period under a request as follows:

(i) The Department will accept an allowance allocation request only if the request meets, or is adjusted by the Department as necessary to meet, the requirements of this section.
(ii) On or after January 1 of the year of allocation, the Department will determine the sum of the CAIR NOx allowances requested.

(4) Up to 1.3% of the Commonwealth¿s CAIR NOx trading budget is available for allocation in each allocation cycle from 2011-2016 to allocate 2010-2015 allowances for the purpose of offsetting SO2 emissions from units described in paragraph (2). Beginning January 1, 2017, and for each allocation cycle thereafter, the units will no longer be allocated CAIR NOx allowances under paragraph (2). Any allowances remaining after this allocation will be allocated to units under subsection (c) during the next allocation cycle.

(5) Notwithstanding the provisions of paragraphs (2)¿(4), the Department may extend, terminate or otherwise modify the allocation of NOx allowances made available under this subsection for units exempted under section 405(g)(6)(a) of the Clean Air Act after providing notice in the Pennsylvania Bulletin and at least a 30-day public comment period.

(g) The Department will correct any errors in allocations made by the Department and discovered after final allocations are made but before the next allocation cycle, in the subsequent allocation cycle using future allowances that have not yet been allocated.

 # 009 [25 Pa. Code §145.213.]

Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.170--96.175.

(a) By January 1, 2009, or by the date of commencing commercial operation, whichever is later, the owner or operator of the CAIR NOx unit shall install, calibrate, maintain and operate a wattmeter, measure gross electrical output in megawatt-hours on a continuous basis and record the output of the wattmeter. If a generator is served by two or more units, the information to determine the heat input of each unit for that control period shall also be recorded, so as to allow each unit¿s share of the gross electrical output to be determined. If heat input data are used, the owner or operator shall comply with the applicable provisions of 40 CFR Part 75 (relating to continuous emission monitoring).

(b) By September 1, 2008, for a CAIR NOx unit that is a cogeneration unit, and for a CAIR NOx unit with cogeneration capabilities, the owner or operator shall install, calibrate, maintain and operate meters for steam flow in lbs/hr, temperature in degrees Fahrenheit, and pressure in PSI, to measure and record the useful thermal energy that is produced, in mmBtu/hr, on a continuous basis. The owner or operator of a CAIR NOx unit that produces useful thermal energy but uses an energy transfer medium other than steam, such as hot water or glycol, shall install, calibrate, maintain and operate the necessary meters to measure and record the data necessary to express the useful thermal energy produced, in mmBtu/hr, on a continuous basis. If the unit ceases to produce useful thermal energy, the owner or operator may cease operation of the meters, but operation of the meters shall be resumed if the unit resumes production of useful thermal energy.

(c) Beginning with 2009, the designated representative of the unit shall submit to the Department an annual report showing monthly gross electrical output and monthly useful thermal energy from the unit. The report is due by January 31 for the preceding calendar year.

(d) The owner or operator of a CAIR NOx unit shall maintain onsite the monitoring plan detailing the monitoring system and maintenance of the monitoring system, including quality assurance activities. The owner or operator of a CAIR NOx unit shall retain the monitoring plan for at least 5 years from the date that it is replaced by a new or revised monitoring plan. The owner or operator of a CAIR NOx unit shall provide the Department with a written copy of the monitoring plan by January 1, 2009, and thereafter within 3 calendar months of making updates to the plan.

(e) The owner or operator of a CAIR NOx unit shall retain records for at least 5 years from the date the record is created or the data collected as required by subsections (a) and (b), and the reports submitted to the Department and the EPA in accordance with subsections (c) and (d).

 # 010 [25 Pa. Code §145.222.]

CAIR NOx Ozone Season allowance allocations.

(a) Provisions not incorporated by reference. The requirements of 40 CFR 96.342 (relating to CAIR NOx Ozone Season allowance allocations) are not incorporated by reference. Instead of 40 CFR 96.342, the requirements in this section apply.

(b) Baseline heat input. Baseline heat input for each CAIR NOx Ozone Season unit will be converted as follows:

(1) A unit¿s control period heat input and a unit¿s status as coal-fired or oil-fired for the ozone season portion of a calendar year under this paragraph will be determined in one of the following two ways:

(i) In accordance with 40 CFR Part 75 (relating to continuous emission monitoring), to the extent that the unit was otherwise subject to the requirements of 40 CFR Part 75 for the control period.

(ii) Based on the best available data reported to the Department for the unit, to the extent the unit was not otherwise subject to the requirements of 40 CFR Part 75 for the year.

(2) Except as provided in subparagraphs (iv) and (v), a unit¿s converted control period heat input for the ozone season portion of a calendar year shall be determined as follows:

(i) The control period gross electrical output of the generators served by the unit multiplied by 7,900 Btu/kWh if the unit is coal-fired for the ozone season control period, and divided by 1,000,000 Btu/mmBtu.

(ii) The control period gross electrical output of the generators served by the unit multiplied by 6,675 Btu/kWh if the unit is not coal-fired for the ozone season control period, and divided by 1,000,000 Btu/mmBtu.

(iii) If a generator is served by 2 or more units, the gross electrical output of the generator will be attributed to each unit in proportion to the share of the total control period heat input from each of the units for the ozone season control period.

(iv) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating or cooling purposes through the sequential use of energy, the total heat energy (in Btus) of the steam produced by the boiler during the ozone season control period, divided by 0.8 and by 1,000,000 Btu/mmBtu.

(v) For a unit that is a combustion turbine and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating or cooling purposes through the sequential use of energy, the control period gross electrical output of the enclosed device comprising the compressor, combustor and turbine multiplied by 3,413 Btu/kWh, plus the total heat energy (in Btu) of the steam produced by any associated heat recovery steam generator during the ozone season control period divided by 0.8, and with the sum divided by 1,000,000 Btu/mmBtu.

(vi) Calculations will be based on the best output data available on or before January 31 of the year the allocations are published. If unit level electrical or steam output data are not available from EIA, or submitted by this date by the owner or operator of the CAIR NOx Ozone Season unit, then heat input data for the period multiplied by 0.25 and converted to MWh will be used to determine total output.

(c) Existing unit, new unit and subsection (f)(1) qualifying resource allocation baseline. For each control period beginning with the 2010 control period and thereafter, the Department will allocate to qualifying resources and CAIR NOx Ozone

Season units, including CAIR NOx Ozone Season units issued allowances under subsection (e), a total amount of CAIR NOx Ozone Season allowances equal to the number of CAIR NOx Ozone Season allowances remaining in the Commonwealth¿s CAIR NOx Ozone Season trading budget under 40 CFR 96.140 (relating to State trading budgets) for those control periods using summed baseline heat input data as determined under subsections (b) and (f)(1) from an ozone season control period in a baseline year that is 6 calendar years before the control period.

(d) Proration of allowance allocations. The Department will allocate CAIR NOx Ozone Season allowances to each existing CAIR NOx Ozone Season unit and qualifying resource in an amount determined by multiplying the amount of CAIR NOx Ozone Season allowances in the Commonwealth¿s CAIR NOx Ozone Season trading budget available for allocation under subsection (c) by the ratio of the baseline heat input of the existing CAIR NOx Ozone Season unit or qualifying resource to the sums of the baseline heat input of existing CAIR NOx Ozone Season units and of the qualifying resources, rounding to the nearest whole allowance as appropriate.

(e) Allocations to new CAIR NOx Ozone Season units. By March 31, 2011, and March 31 each year thereafter, the Department will allocate CAIR NOx Ozone Season allowances under § 145.221(c) (relating to timing requirements for CAIR NOx Ozone Season allowance allocations) to CAIR NOx Ozone Season units equal to the previous year¿s emissions at each unit, unless the unit has been issued allowances of the previous year¿s vintage in a regular allocation under § 145.221(b). The Department will allocate CAIR NOx allowances under this subsection of a vintage year that is 5 years later than the year in which the emissions were generated. The number of CAIR NOx Ozone Season allowances allocated shall not exceed the actual emission of the year preceding the year in which the Department makes the allocation. The allocation of these allowances to the new unit will not reduce the number of allowances the unit is entitled to receive under another provision of this subchapter.

(f) Allocations to qualifying resources. For each control period beginning with the 2010 control period, and thereafter, the Department will allocate CAIR NOx Ozone Season allowances to qualifying resources in this Commonwealth that are not also allocated CAIR NOx Ozone Season allowances under another provision of this subchapter, as follows:

(1) The Department will allocate CAIR NOx Ozone Season allowances to a renewable energy qualifying resource or demand side management energy efficiency qualifying resource in accordance with subsections (c) and (d) upon receipt by the Department of an application, in writing, on or before June 30 of the year following the control period, except for vintage year 2011 and 2012 NOx Ozone Season allowance allocations whose application deadline will be prescribed by the Department, meeting the requirements of this paragraph. The number of allowances allocated to the qualifying resource will be determined by converting the certified quantity of electric energy production, useful thermal energy, and energy equivalent value of the measures approved under the Pennsylvania Alternative Energy Portfolio Standard to equivalent thermal energy. Equivalent thermal energy is a unit¿s baseline heat input for allocation purposes. The conversion rate for converting electrical energy to equivalent thermal energy is 3,413 Btu/kWh. To receive allowances under this subsection, the qualifying resource must have commenced operation after January 1, 2005, must be located in this Commonwealth and may not be a CAIR NOx Ozone Season unit. The following procedures apply:

(i) The owner of a qualifying renewable energy resource shall appoint a CAIR-authorized account representative and file a certificate of representation with the EPA and the Department.

(ii) The Department will transfer the allowances into an account designated by the owner¿s CAIR-authorized account representative of the qualifying resource, or into an account designated by an aggregator approved by the Pennsylvania Public Utility Commission or its designee.

(iii) The applicant shall provide the Department with the corresponding renewable energy certificate serial numbers.

(iv) At least one whole allowance must be generated per owner, operator or aggregator for an allowance to be issued.

(g) The Department will correct any errors in allocations made by the Department and discovered after final allocations are made but before the next allocation cycle, in the subsequent allocation cycle using future allowances that have not yet been allocated.

 # 011 [25 Pa. Code §145.223.]

Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.370--96.375.

(a) By January 1, 2009, or by the date of commencing commercial operation, whichever is later, the owner or operator of the CAIR NOx Ozone Season unit shall install, calibrate, maintain and operate a wattmeter, measure gross electrical output in megawatt-hours on a continuous basis and record the output of the wattmeter. If a generator is served by two or more units, the information to determine the heat input of each unit for that control period shall also be recorded, so as to allow each unit¿s share of the gross electrical output to be determined. If heat input data are used, the owner or operator shall comply with the applicable provisions of 40 CFR Part 75 (relating to continuous emission monitoring).

(b) By September 1, 2008, for a CAIR NOx Ozone Season unit that is a cogeneration unit, and for a CAIR NOx Ozone Season unit with cogeneration capabilities, the owner or operator shall install, calibrate, maintain and operate meters for steam flow in lbs/hr, temperature in degrees Fahrenheit and pressure in PSI, to measure and record the useful thermal energy that is produced, in mmBtu/hr, on a continuous basis. The owner or operator of a CAIR NOx Ozone Season unit that produces useful thermal energy but uses an energy transfer medium other than steam, such as hot water or glycol, shall install, calibrate, maintain and operate the necessary meters to measure and record the data necessary to express the useful thermal energy produced, in mmBtu/hr, on a continuous basis. If the unit ceases to produce useful thermal energy, the owner or operator may cease operation of the meters, but operation of the meters shall be resumed if the unit resumes production of useful thermal energy.

(c) Beginning with 2009, the designated representative of the unit shall submit to the Department an annual report showing monthly gross electrical output and monthly useful thermal energy from the unit. The report is due by January 31 for the preceding calendar year.

(d) The owner or operator of a CAIR NOx Ozone Season unit shall maintain onsite the monitoring plan detailing the monitoring system and maintenance of the monitoring system, including quality assurance activities. The owner or operator of a CAIR NOx Ozone Season unit shall retain the monitoring plan for at least 5 years from the date that it is replaced by a new or revised monitoring plan. The owner or operator of a CAIR NOx Ozone Season unit shall provide the Department with a written copy of the monitoring plan by January 1, 2009, and thereafter within 3 calendar months of making updates to the plan.

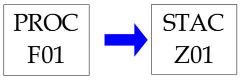
(e) The owner or operator of a CAIR NOx Ozone Season unit shall retain records for at least 5 years from the date the record is created or the data collected as required by subsections (a) and (b), and the reports submitted to the Department and the EPA in accordance with subsections (c) and (d).

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: F01 Source Name: PLANT HAUL ROADS

Source Capacity/Throughput:



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.441]

Operating permit terms and conditions.

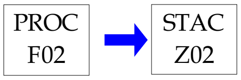
Source ID F01 consists of the various facility roads that are used for transporting coal, oil, ash for disposal, etc. at the facility.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: F02 Source Name: COAL HANDLING AND STORAGE

Source Capacity/Throughput:



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID F02 is all coal handling operation at the facility that include: hopper loading, conveying, breaking, transferring, bulldozing, storage, wind erosion, etc. at the facility.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: F03 Source Name: ASH DISPOSAL FACILITY

Source Capacity/Throughput:

PROC F03 → STAC Z03

I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

There shall be no fugitive emissions from the loads contained in the trucks serving the Shawville Station other than what the Department determines to be of minor significance.

Throughput Restriction(s).

 # 002 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

(a) The total amount of ash disposed at the ash disposal facility shall not exceed 261,000 tons in any 12 consecutive month period.

(b) The total amount of soil transferred from the facility property to the ash disposal facility and soil transported from offsite locations to the ash disposal facility (soil borrow) shall not exceed 18,121 tons in any 12 consecutive month period.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

 # 003 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

The permittee shall keep records on a monthly basis of:

(a) The total amount of ash disposed in Source ID F03 in tons and the corresponding 12 consecutive month running total to verify compliance with the ash disposal limitation.

(b) The total amount of soil transferred from the facility property to Source ID F03, the amount of soil transported from offsite locations to Source ID F03 in tons and the corresponding 12 consecutive month running total to verify compliance with the "soil borrow" limitation.

(c) The total amount of miscellaneous coal ash and waste coal disposed of in Source ID F03 in tons.

(d) The total amount of refractory material and concrete construction/demolition waste disposed of in Source ID F03 in tons.

(e) The total amount of sandblast abrasive and residue, other than that which is washed out of the boilers and sluiced to the bottom ash ponds, disposed of in Source ID F03 in tons.

All such records shall be retained for a minimum of five years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

 # 004 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

The raw water supply system at the facility shall provide an adequate supply of water to the fly ash unloaders and paddle mixer associated with the facility's fly ash silos under all plant operating conditions.

 # 005 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

All ash disposed of in Source ID F03 shall be properly conditioned with water prior to disposal. The only fly ash to be disposed of in this ash disposal facility shall be fly ash which has been properly conditioned with water in the fly ash unloaders and paddle mixers associated with the fly ash silos.

 # 006 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

A water truck equipped with both a pressurized spray bar and a pressurized hose or spray nozzle shall be maintained on site at all times. Said water truck shall be used as necessary to minimize fugitive particulate matter emissions from all roadways. The permittee shall implement all winterization measures necessary to render this water truck capable of use under all weather conditions.

 # 007 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

All ash hauled to the disposal facility during the course of a day shall be dumped, spread and compacted by the end of that day.

 # 008 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

All disposal areas shall be covered with soil and/or bottom ash and vegetated upon cessation of active use.

SECTION D. Source Level Requirements

VII. ADDITIONAL REQUIREMENTS.

 # 009 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID F03 consists of all ash disposal operations at the Shawville facility including: silo transfer and storage, unloading, spreading, bulldozing, wind erosion, etc. at the facility.

 # 010 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

(a) The only wastes to be disposed of in Source ID F03 shall be the following:

(1) Ash from the Shawville Generating Station or ash from off site coal fired power generation plants.

(2) Miscellaneous coal ash and waste coal, which includes street cleaner refuse, cleaning refuse from ash hopper trenches, vacuum truck boiler refuse and coal spillage, provided the street cleaner refuse and vacuum truck boiler refuse are contained until disposal at the active surface of the disposal site and provided that water is applied to these wastes during disposal, as needed, to control emission of fugitive particulate matter.

(3) Ash pond sediments, which include reject coal and pyrites from the coal mills, water and treatment sludge and wastewater clarifier sludge, provided all these materials contain sufficient moisture content to prevent the emission of fugitive particulate matter during disposal.

(4) Refractory material and concrete concentration/demolition waste provided water is applied, as needed, to control the emission of fugitive particulate matter during disposal.

(5) Sandblast abrasive and residue provided any such material either contains sufficient moisture content to prevent the emission of particulate matter during disposal or water is applied to the material, as needed, to control the emission of particulate matter during disposal.

(6) Filter media/spent demineralization resin provided this material contains sufficient moisture content to prevent the emission of particulate matter during disposal.

(7) Asbestos-containing waste provided it is classified as non-friable and is double wrapped in plastic.

(b) The permittee shall not dispose of any other types of wastes in Source ID F03 unless prior approval is granted from the Department's Air Quality and Waste Management Programs.

 # 011 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

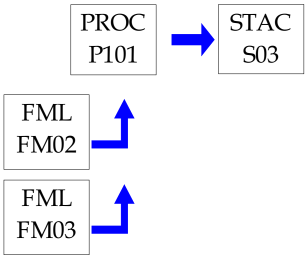
All trucks transporting ash from all offsite locations shall be fully tarped (affixed with a tarp covering the entire truck bed opening) during all times of transport.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: P101 Source Name: STARTUP GENERATOR 5

Source Capacity/Throughput:



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.13]

Processes

No person shall permit the emission of particulate matter from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of particulate matter in the effluent gas exceeds 0.04 grain per dry standard cubic foot.

 # 002 [25 Pa. Code §123.21]

General

No person may permit the emission from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of the sulfur oxides (SOX), expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, dry basis.

Fuel Restriction(s).

 # 003 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall only fire #2 or lighter fuel oil in Source ID P101.

Operation Hours Restriction(s).

 # 004 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall limit the operation of Source ID P101 to less than a 5% capacity factor in any 12 consecutive month period.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

 # 005 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95. The records shall clearly demonstrate that the annual capacity factor for Source ID P101 is less than 5%.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

 # 006 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall annually report records of supporting calculations that clearly demonstrate that the annual capacity factor for Source ID P101 is less than 5%.

Annual reports shall be submitted to the Department by no later than March 1 for the preceeding year.

 # 007 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall calculate and report the annual mass emissions for CO2, N2H and CH4 from Source IDs P101 through P103 in accordance with the requirements of 40 CFR Part 98 Subpart C.

VI. WORK PRACTICE REQUIREMENTS.

 # 008 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall maintain and operate Source ID P101 in accordance with the manufacturers specifications.

VII. ADDITIONAL REQUIREMENTS.

 # 009 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID P101 (Unit 5) is a 2880 hp, General Motors diesel engine.

 # 010 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 63.6580]

(a) Source ID P101 is subject to 40 CFR Part 63, Subpart ZZZZ. The permittee shall comply with all the applicable requirements specified in 40 CFR Sections 63.6580 through 63.6675.

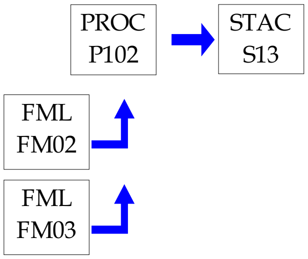
(b) The compliance date of Source ID P101 for 40 CFR Part 63, Subpart ZZZZ is May 3, 2013. The permittee shall submit a minor operating permit modification application to the Department by January 1, 2013 to incorporate the applicable conditions of 40 CFR Part 63, Subpart ZZZZ into TVOP 17-00001.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: P102 Source Name: STARTUP GENERATOR 6

Source Capacity/Throughput:



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.13]

Processes

No person shall permit the emission of particulate matter from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of particulate matter in the effluent gas exceeds 0.04 grain per dry standard cubic foot.

 # 002 [25 Pa. Code §123.21]

General

No person may permit the emission from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of the sulfur oxides (SOX), expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, dry basis.

Fuel Restriction(s).

 # 003 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall only fire #2 or lighter fuel oil in Source ID P102.

Operation Hours Restriction(s).

 # 004 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall limit the operation of Source ID P102 to less than a 5% capacity factor in any 12 consecutive month period.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

 # 005 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95. The records shall clearly demonstrate that the annual capacity factor for Source ID P102 is less than 5%.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

 # 006 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall annually report records of supporting calculations that clearly demonstrate that the annual capacity factor for Source ID P102 is less than 5%.

Annual reports shall be submitted to the Department by no later than March 1 for the preceeding year.

 # 007 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall calculate and report the annual mass emissions for CO2, N2H and CH4 from Source IDs P101 through P103 in accordance with the requirements of 40 CFR Part 98 Subpart C.

VI. WORK PRACTICE REQUIREMENTS.

 # 008 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall maintain and operate Source ID P102 in accordance with the manufacturers specifications.

VII. ADDITIONAL REQUIREMENTS.

 # 009 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID P102 (Unit 6) is a 2880 hp, General Motors diesel engine.

 # 010 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 63.6580]

(a) Source ID P102 is subject to 40 CFR Part 63, Subpart ZZZZ. The permittee shall comply with all the applicable requirements specified in 40 CFR Sections 63.6580 through 63.6675.

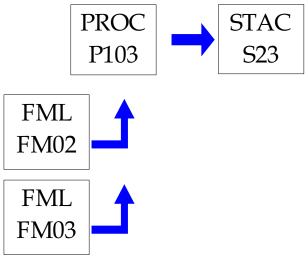
(b) The compliance date of Source ID P102 for 40 CFR Part 63, Subpart ZZZZ is May 3, 2013. The permittee shall submit a minor operating permit modification application to the Department by January 1, 2013 to incorporate the applicable conditions of 40 CFR Part 63, Subpart ZZZZ into TVOP 17-00001.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: P103 Source Name: STARTUP GENERATOR 7

Source Capacity/Throughput:



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.13]

Processes

No person shall permit the emission of particulate matter from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of particulate matter in the effluent gas exceeds 0.04 grain per dry standard cubic foot.

 # 002 [25 Pa. Code §123.21]

General

No person may permit the emission from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of the sulfur oxides (SOX), expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, dry basis.

Fuel Restriction(s).

 # 003 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall only fire #2 or lighter fuel oil in Source ID P103.

Operation Hours Restriction(s).

 # 004 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall limit the operation of Source ID P103 to less than a 5% capacity factor in any 12 consecutive month period.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

SECTION D. Source Level Requirements

IV. RECORDKEEPING REQUIREMENTS.

 # 005 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95. The records shall clearly demonstrate that the annual capacity factor for Source ID P103 is less than 5%.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

 # 006 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall annually report records of supporting calculations that clearly demonstrate that the annual capacity factor for Source ID P103 is less than 5%.

Annual reports shall be submitted to the Department by no later than March 1 for the preceeding year.

 # 007 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall calculate and report the annual mass emissions for CO2, N2H and CH4 from Source IDs P101 through P103 in accordance with the requirements of 40 CFR Part 98 Subpart C.

VI. WORK PRACTICE REQUIREMENTS.

 # 008 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall maintain and operate Source ID P103 in accordance with the manufacturers specifications.

VII. ADDITIONAL REQUIREMENTS.

 # 009 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID P103 (Unit 7) is a 2880 hp, General Motors diesel engine.

 # 010 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 63.6580]

(a) Source ID P103 is subject to 40 CFR Part 63, Subpart ZZZZ. The permittee shall comply with all the applicable requirements specified in 40 CFR Sections 63.6580 through 63.6675.

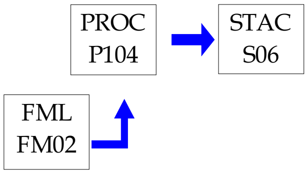
(b) The compliance date of Source ID P103 for 40 CFR Part 63, Subpart ZZZZ is May 3, 2013. The permittee shall submit a minor operating permit modification application to the Department by January 1, 2013 to incorporate the applicable conditions of 40 CFR Part 63, Subpart ZZZZ into TVOP 17-00001.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: P104 Source Name: EMERGENCY GENERATOR 1(UNIT 1-2)

Source Capacity/Throughput:



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.13]

Processes

No person shall permit the emission of particulate matter from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of particulate matter in the effluent gas exceeds 0.04 grain per dry standard cubic foot.

 # 002 [25 Pa. Code §123.21]

General

No person may permit the emission from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of the sulfur oxides (SOX), expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, dry basis.

Fuel Restriction(s).

 # 003 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall only fire #2 or lighter fuel oil in Source ID P104.

Operation Hours Restriction(s).

 # 004 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall limit the operation of Source ID P104 to less than 500 hours in any 12 consecutive month period.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

 # 005 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95. The records shall, at a minimum, include data that clearly demonstrates that Source ID P104 has operated less than 500 hours in any twelve consecutive month period.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

 # 006 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall report annually the total number of hours that the subject source has been operated.

(b) Annual report shall be submitted to the Department no later than March 1 for the preceding year.

VI. WORK PRACTICE REQUIREMENTS.

 # 007 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall maintain and operate the Source ID P104 in accordance with manufacturers specifications.

VII. ADDITIONAL REQUIREMENTS.

 # 008 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID P104 (Unit 1-2) consists of a model #62400RA, 254 horsepower, General Motors diesel emergency generator.

 # 009 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 63.6580]

(a) Source ID P104 is subject to 40 CFR Part 63, Subpart ZZZZ. The permittee shall comply with all the applicable requirements specified in 40 CFR Sections 63.6580 through 63.6675.

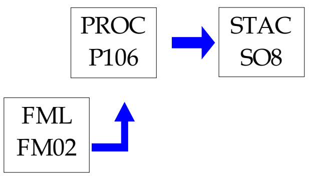
(b) The compliance date of Source ID P104 for 40 CFR Part 63, Subpart ZZZZ is May 3, 2013. The permittee shall submit a minor operating permit modification application to the Department by January 1, 2013 to incorporate the applicable conditions of 40 CFR Part 63, Subpart ZZZZ into TVOP 17-00001.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: P106 Source Name: 2 FIRE PUMP ENGINES

Source Capacity/Throughput:



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.13]

Processes

No person shall permit the emission of particulate matter from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of particulate matter in the effluent gas exceeds 0.04 grain per dry standard cubic foot.

 # 002 [25 Pa. Code §123.21]

General

No person may permit the emission from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of the sulfur oxides (SOX), expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, dry basis.

Fuel Restriction(s).

 # 003 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall only fire #2 or lighter fuel oil in each engine of Source ID P106.

Operation Hours Restriction(s).

 # 004 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall limit the operation of each engine of Source ID P106 to less than 500 hours in any 12 consecutive month period.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

 # 005 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95. The records shall, at a minimum, include data that clearly demonstrates that each engine of Source ID P106 has operated less than 500 hours in any twelve consecutive month period.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

 # 006 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall report annually the total number of hours that the subject source has been operated.

(b) Annual report shall be submitted to the Department no later than March 1 for the preceding year.

VI. WORK PRACTICE REQUIREMENTS.

 # 007 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall maintain and operate each engine of Source ID P106 in accordance with manufacturers specifications.

VII. ADDITIONAL REQUIREMENTS.

 # 008 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source ID P106 is 2 model #NT-380-IF, 283 horsepower, Cummings diesel fire pump engines.

 # 009 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 63.6580]

(a) Source ID P106 is subject to 40 CFR Part 63, Subpart ZZZZ. The permittee shall comply with all the applicable requirements specified in 40 CFR Sections 63.6580 through 63.6675.

(b) The compliance date of Source ID P106 for 40 CFR Part 63, Subpart ZZZZ is May 3, 2013. The permittee shall submit a minor operating permit modification application to the Department by January 1, 2013 to incorporate the applicable conditions of 40 CFR Part 63, Subpart ZZZZ into TVOP 17-00001.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: P116 Source Name: WATER TREATMENT OPERATIONS

Source Capacity/Throughput:

PROC P116 → STAC Z116

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.441]

Operating permit terms and conditions.

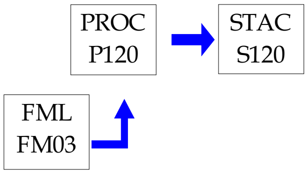
The water treatment operations of P116 include all activities and processes associated with treating wastewater at the facility. It includes: the lime silo with fabric filter, clarifying pools, mixing and settling tanks, all pH adjustment proceedures and all other wastewater treatment conducted at the facility.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: P120 Source Name: EMERGENCY DIESEL GENERATOR

Source Capacity/Throughput:



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.13]

Processes

No person may permit the emission into the outdoor atmosphere of particulate matter from the exhaust associated with Source ID P120 in a manner that the concentration in the effluent gas exceeds 0.04 grains per dry standard cubic foot.

 # 002 [25 Pa. Code §123.21]

General

No person may permit the emission into the outdoor atmosphere of sulfur oxides from Source ID P120 in a manner that the concentration of the sulfur oxides, expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, on a dry basis.

Fuel Restriction(s).

 # 003 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID P120 shall only be fired on No. 2 fuel oil.

Operation Hours Restriction(s).

 # 004 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID P120 shall not be operated in excess of 500 hours in any 12 consecutive month period.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

 # 005 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The permittee shall keep comprehensive and accurate records of the following:

(a) The amount of hours that Source ID P120 is operated each month and keep calculations which verify the 12 consecutive month operational limitation for Source ID P120.

(b) Supporting calculations to verify compliance with the particulate matter and sulfur oxide emission limitations for Source

ID P120.

These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VII. ADDITIONAL REQUIREMENTS.

 # 006 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID P120 is a diesel fired Caterpillar model D200P3 emergency generator rated at 242 kilowatts

 # 007 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 63.6580]

(a) Source ID P120 is subject to 40 CFR Part 63, Subpart ZZZZ. The permittee shall comply with all the applicable requirements specified in 40 CFR Sections 63.6580 through 63.6675.

(b) The compliance date of Source ID P120 for 40 CFR Part 63, Subpart ZZZZ is May 3, 2013. The permittee shall submit a minor operating permit modification application to the Department by January 1, 2013 to incorporate the applicable conditions of 40 CFR Part 63, Subpart ZZZZ into TVOP 17-00001.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: P121 Source Name: PARTS WASHERS

Source Capacity/Throughput:

PROC P121 → STAC Z121

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

 # 001 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 129.63]

The permittee shall keep records of Certified Product Data Sheets (CPDSs) or Material Safety Data Sheets (MSDSs) that identify the volatile organic compound (VOC) and HAP content of the solvents used in Source ID P121.

 # 002 [25 Pa. Code §129.63]

Degreasing operations

The permittee shall maintain for a minimum of five (5) years and present to the Department upon request the following information:

(1) The name and address of the solvent supplier,

(2) The type of solvent including the product or vendor identification number,

(3) The vapor pressure of the solvent measured in millimeters of mercury (mm Hg) at 68 degrees Fahrenheit.

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

 # 003 [25 Pa. Code §129.63]

Degreasing operations

Each parts washer of Source ID P121 shall be operated in accordance with the following procedures:

(1) Waste solvent shall be collected and stored in a closed container. The closed container may contain a device that allows pressure relief, but does not allow liquid solvent to drip from the container.

(2) Flushing of parts using a flexible hose or other flushing device shall be performed only within the cold cleaning machine. The solvent spray shall be a solid fluid stream, not an atomized or shower spray.

(3) Sponges, fabric, wood, leather, paper products, and other absorbent materials may not be cleaned in the cold cleaning machine.

(4) Air agitated solvent baths may not be used.

(5) Spills during solvent transfer and use of cold cleaning machine shall be cleaned up immediately.

VII. ADDITIONAL REQUIREMENTS.

 # 004 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID P121 is subject to 25 Pa. Code Section 129.63(a) (Degreasing Operations - Cold Cleaning Machines). The permittee shall comply with all applicable requirements specified in 25 Pa. Code Section 129.63(a).

 # 005 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 129.63]

The vapor pressure of VOC containing solvent shall be less than 1.0 millimeter of mercury (mm Hg) measured at 20 degrees Celsius (68 degrees Fahrenheit).

 # 006 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID P121 consists of two (2) parts washers used in the shop area.

 # 007 [25 Pa. Code §129.63]

Degreasing operations

Each parts washer of Source ID P121 shall have a freeboard ratio of 0.50 or greater.

 # 008 [25 Pa. Code §129.63]

Degreasing operations

Each parts washer of Source ID P121 shall have a permanent, conspicuous label summarizing all required operating procedures specified in Condition #003 for Source ID P121. In addition, the label shall include the following discretionary good operating practices:

(1) Cleaned parts should be drained at least 15 seconds or until dripping ceases, whichever is longer. Parts having cavities or blind holes shall be tipped or rotated while the part is draining.

(2) During the draining, tipping, or rotating, the parts should be positioned so that solvent drains directly back to the cold cleaning machine.

(3) Work area fans should be located and positioned so that they do not blow across the opening of the degreaser unit.

 # 009 [25 Pa. Code §129.63]

Degreasing operations

Each parts washer of Source ID P121 shall be equipped with a cover that shall be closed at all times except during the cleaning of parts or the addition or removal of solvent. For Source ID P121, a perforated drain with a diameter of not more than 6 inches shall constitute an acceptable cover.

***** Permit Shield in Effect. *****

SECTION E. Alternative Operation Requirements.

No Alternative Operations exist for this Title V facility.

SECTION F. Emission Restriction Summary.

Source Id	Source Description
031	UTILITY BOILER - UNIT 1

Emission Limit			Pollutant
0.003	Lbs/MMBTU	ammonia	Ammonia (Aqueous Soll Conc. 20
5.000	PPMV	corrected to 8% oxygen	Ammonia (Aqueous Soll Conc. 20
0.524	Lbs/MMBTU	30-day rolling average	NOX
3.700	Lbs/MMBTU	30-day rolling average	SOX
4.000	Lbs/MMBTU	2 day ave. in any 30 days	SOX
4.000	Lbs/MMBTU	at any time	SOX
4.800	Lbs/MMBTU	daily average	SOX
0.100	Lbs/MMBTU		TSP

Source Id	Source Description
032	UTILITY BOILER - UNIT 2

Emission Limit			Pollutant
0.003	Lbs/MMBTU	ammonia	Ammonia (Aqueous Soll Conc. 20
5.000	PPMV	corrected to 8% oxygen	Ammonia (Aqueous Soll Conc. 20
0.542	Lbs/MMBTU	30-day rolling average	NOX
3.700	Lbs/MMBTU	30-day rolling average	SOX
4.000	Lbs/MMBTU	2 day ave. in any 30 days	SOX
4.000	Lbs/MMBTU	at any time	SOX
4.800	Lbs/MMBTU	daily average	SOX
0.100	Lbs/MMBTU		TSP

Source Id	Source Description
033	UTILITY BOILER - UNIT 3

Emission Limit			Pollutant
5.000	PPMV	corrected to 8% oxygen	Ammonia (Aqueous Soll Conc. 20
0.450	Lbs/MMBTU	30-day rolling average	NOX
3.700	Lbs/MMBTU	30-day rolling average	SOX
4.000	Lbs/MMBTU	2 day ave. in any 30 days	SOX
4.000	Lbs/MMBTU	at any time	SOX
4.800	Lbs/MMBTU	daily average	SOX
0.100	Lbs/MMBTU		TSP

Source Id	Source Description
034	UTILITY BOILER - UNIT 4

Emission Limit			Pollutant
5.000	PPMV	corrected to 8% oxygen	Ammonia (Aqueous Soll Conc. 20
0.450	Lbs/MMBTU	30-day rolling average	NOX
3.700	Lbs/MMBTU	30-DAY ROLLING AVERAGE	SOX
4.000	Lbs/MMBTU	2 day ave. in any 30 days	SOX
4.000	Lbs/MMBTU	AT ANY TIME	SOX
4.800	Lbs/MMBTU	daily average	SOX
0.100	Lbs/MMBTU		TSP

Source Id	Source Description
038	15 SPACE HEATERS

Emission Limit			Pollutant
500.000	PPMV		SOX
0.040	gr/DRY FT3		TSP

SECTION F. Emission Restriction Summary.

Source Id	Source Description

P101 STARTUP GENERATOR 5

Emission Limit		Pollutant
500.000	PPMV	SOX
0.040	gr/DRY FT3	TSP

P102 STARTUP GENERATOR 6

Emission Limit		Pollutant
500.000	PPMV	SOX
0.040	gr/DRY FT3	TSP

P103 STARTUP GENERATOR 7

Emission Limit		Pollutant
500.000	PPMV	SOX
0.040	gr/DRY FT3	TSP

P104 EMERGENCY GENERATOR 1(UNIT 1-2)

Emission Limit		Pollutant
500.000	PPMV	SOX
0.040	gr/DRY FT3	TSP

P106 2 FIRE PUMP ENGINES

Emission Limit		Pollutant
500.000	PPMV	SOX
0.040	gr/DRY FT3	TSP

P120 EMERGENCY DIESEL GENERATOR

Emission Limit		Pollutant
500.000	PPMV	SOX
0.040	gr/DRY FT3	TSP

Site Emission Restriction Summary

Emission Limit	Pollutant

SECTION F. Emission Restriction Summary.

SECTION G. Miscellaneous.

(1) The following air contaminant sources are considered to be of minor significance to the Department and have been determined to be exempt from permit requirements. However, this determination does not exempt the sources from compliance with all applicable air quality regulations specified in 25 Pa. Code Chapters 121-143:

(a) There are 12 storage tanks at this facility that have a capacity that is less than 2000 gallons. They include:

1. ash landfill area diesel fuel oil storage tank - 1000 gallon
2. ash landfill area gasoline storage tank - 500 gallon
3. ash landfill area waste oil tank - 250 gallon
4. ash landfill area waste oil tank - 300 gallon
5. 2 ash landfill area lube oil tanks - 500 gallon each
6. sulfuric acid storage tank - 1,000 gallon
7. 5 day-tanks for generators - 100 gallons each

(b) There are 15 storage tanks at this facility that have a capacity that is greater than 2000 gallons used to store liquids having vapor pressures less than 1.5 psia. They include:

1. #2 oil storage tank - 500,000 gallons
2. 2 startup diesel (a blend of #1 and #2 fuel oil) fuel storage tanks - 20,000 gallons each
3. 2 waste oil storage tanks - 3,000 gallons each
4. 3 lube oil storage tanks - 5,000 gallons each
5. an ethylene glycol storage tank - 5,000 gallons
6. a 6% caustic storage tank - 5,000 gallons
7. a 50% caustic storage tank - 2,800 gallons
8. a 50% caustic storage tank - 10,000 gallons
9. a FWWT 20% caustic storage tank - 7,500 gallons
10. a Sulfuric acid storage tank - 10,000 gallons
11. an Anhydrous ammonia storage tank - 10,000 gallons

(c) 2 mechanical draft cooling towers.

(d) Fly ash silos and Limestone silos.

(2) Attached to this permit is the Phase II Title IV (Acid Rain) permit in its entirety, renewed on May 29, 2009 and effective through December 31, 2012. Certain requirements from the Acid Rain permit have been reiterated in the body of the Title V permit for emphasis. The entire Title IV permit is incorporated into this Title V permit by inclusion.

(3) The applicable emission restrictions and operating requirements for the Shawville Generating Station are set forth in Sections C through G of this permit. The general Title V requirements of Section B in this permit continue in full force and effect.

****** End of Report ******

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CLUB
FOUNDED 1892

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January 4, 2011

VIA ELECTRONIC MAIL AND U.S. MAIL

Re: RRI Energy Mid Atlantic Power Holdings LLC – Shawville Generating Station Draft Title V/State Operating Permit (ID No. 17-00001)

Dear Muhammad Zaman,

The Sierra Club submits the following comments regarding the draft Title V/State Operating Permit published by the Commonwealth of Pennsylvania Department of Environmental Protection ("DEP") for the RRI Mid Atlantic Power Holdings LLC ("RRI") Shawville Generating Station in Clearfield County, Pennsylvania ("the Shawville Plant" or "the Plant").

A. The Sierra Club Has an Interest in the Environmental Impacts of the Shawville Plant

The Shawville Plant is a four-boiler 626 megawatt coal-fired power plant located in Clearfield County, Pennsylvania, all of whose boilers came on-line between 1954 and 1960. The Plant lacks many basic emissions control technologies, such as flue gas desulfurization ("FGD") devices. RRI filed a renewal Title V application on April 29, 2010, but a renewal permit has yet to be issued.

The Sierra Club is the oldest and largest grassroots environmental group, with over 617,000 activists and members, including nearly 24,000 in Pennsylvania. Sierra Club members live, work, attend school, travel and recreate in areas adversely affected by the

Shawville Plant's emissions. Our members enjoy and are entitled to the benefits of natural resources that are adversely affected by air pollution, including air, water and soil; forests and cropland; parks, wilderness areas and other green space; and flora and fauna. The activities enjoyed by our membership that are affected by the Shawville Plant's emissions include breathing, exercising, sports, walking, hiking and work-related activities. Our membership and their families include members of sensitive populations such as asthmatics, the elderly and children who are at elevated risk for the deleterious health effects posed by coal fired boiler emissions, such as those generated by the Shawville Plant. In particular, the Sierra Club's members are adversely impacted by the air pollution emitted by the Shawville Plant, which is a major source of sulfur dioxide (32,973 tons in 2009), nitrogen oxides (4,690 tons in 2009), particulate matter (including PM_{10} and $PM_{2.5}$, 2,644 and 2,249 tons in 2002, respectively), carbon monoxide (332 tons in 2002), and carbon dioxide (2,368,168 tons in 2009).

B. The Sierra Club's Concerns with the Draft Permit

The Title V program plays a critical role in enabling an industrial facility, government regulators, and the public to identify all applicable requirements that apply to a facility's air pollution emissions and to determine whether the facility is complying with those requirements. One purpose of the Title V program is to enable the source, EPA, states, and the public to better understand the applicable requirements to which the source is subject and whether the source is meeting them.[1] However, the draft permit for the Shawville Plant fails in several key respects to require performance consistent with the Clean Air Act and Pennsylvania's State Implementation Plan ("SIP") or monitoring sufficient to ensure compliance with applicable law. Specifically, the Sierra Club has the following concerns with the draft permit, each discussed in greater detail below:

- The Draft Permit lacks sufficient periodic monitoring regarding the Plant's particulate matter emissions;
- The Draft Permit includes inadequate compliance monitoring requirements regarding the Plant's particulate matter emissions;
- The Draft Permit lacks a compliance schedule for remedying significant, ongoing violations of the Clean Air Act;
- The Draft Permit fails to ensure that the plant will not cause or contribute to violations of the new one-hour NAAQS for SO_2;

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[1] *Sierra Club v. Georgia Power Co.*, 443 F.3d 1346, 1348 (11th Cir. 2006) ("The intent of Title V is to consolidate into a single document (the operating permit) all of the clean air requirements applicable to a particular source of air pollution."); *see also Com. of Va. v. Browner*, 80 F.3d 869, 873 (4th Cir. 1996) ("[A] permit is a source-specific bible for Clean Air Act compliance").

- The Draft Permit fails to ensure that the plant will not cause or contribute to violations of the new one-hour NAAQS for NO_2; and
- The Draft Permit does not provide sufficient specificity in its requirements for continuous emissions monitoring for SO_2, CO_2, and NO_x , as required by 40 C.F.R. § 75.10.

The Sierra Club accordingly urges DEP to correct these defects before issuing any final Title V permit for the Shawville Plant.

C. Detailed Discussion of The Sierra Club's Concerns

The Draft Permit Lacks Adequate Periodic Monitoring Regarding Shawville's Particulate Matter Emissions Emissions

As presently written, the draft permit's monitoring requirements for particulate matter emissions fail to comport with governing law.

The Clean Air Act is intended to protect and enhance the public health and public welfare of the nation. *See* 42 U.S.C. § 7401(b)(1). Pursuant to the Act, EPA promulgates regulations establishing primary and secondary national air ambient quality standards ("NAAQS") for certain pollutants. See 42 U.S.C. § 7409. Primary NAAQS must be set at a level adequate to protect public health with an adequate margin of safety. *See id.* Secondary NAAQS must be set at a level that is protective of the public welfare. *See id.* Each state must adopt and submit for approval a State Implementation Plan ("SIP"), subject to EPA approval, that provides legally enforceable measures to achieve the NAAQS that EPA sets. 42 U.S.C. § 7410(a).

These measures are then applied to specific major emissions sources through what are referred to as Title V permits—permits which major sources must obtain in order to operate legally. *See* 42 § U.S.C. § 7661-1(f). The provisions in 42 U.S.C. § 7661(a) and 25 Pa. Code § 127.444 make it unlawful for any person to violate any requirement of an operating permit issued under Title V.

As is applicable to the Shawville Plant at issue here, Pennsylvania's regulations provide that, for particulate matter, a "person may not permit the emission into the outdoor atmosphere of particulate matter from a combustion unit in excess of . . . [t]he rate of 0.1 pounds per million Btu of heat input when the heat input to the combustion unit in millions of Btus per hour is equal to or greater than 600." 25 Pa. Code § 123.11(3). The averaging time for sampling such emissions is one hour. *See* 25 Pa. Code § 139.12(4). Similarly, a "person may not permit the emission into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following: (1) Equal to or greater than 20% for a period or periods aggregating more than 3 minutes in any 1 hour. (2) Equal to or greater than 60% at any time." 25 Pa. Code § 123.41.

Monitoring requirements in Title V permits must be set so as to "assure use of terms, test methods, units, averaging periods, and other statistical conventions consistent with the applicable requirement." 40 C.F.R. § 70.6(a)(3)(i)(B). Essentially, the Clean Air Act requires that "each permit issued under [Title V] shall set forth . . . monitoring . . . requirements sufficient to assure compliance with the permit terms and conditions." 42 U.S.C. §7661(c). Indeed, the D.C. Circuit Court of Appeals rejected an EPA rule that limited monitoring provisions in Title V permits, explaining that "a monitoring requirement insufficient 'to assure compliance' with emission limits has no place in a permit unless and until it is supplemented by more rigorous standards." *See Sierra Club v. EPA*, 536 F.3d 673, 677 (D.C. Cir. 2008). As the Court explained, annual testing is unlikely to assure compliance with a daily emission limit. *Id.* at 675. *See also In Re Luke Paper Company*, EPA Appeals Board, Permit No. 24-001-00011 (October 10, 2010). In other words, the frequency of monitoring must correlate in some manner to the averaging time used to determine compliance. Moreover, monitoring must assure *continuous* compliance where emission limits have instantaneous parameters.

Here, the emission limits for particulate matter set by the SIP (and incorporated into the draft permit) must be met at all times: particulate matter must never exceed the rate of "0.1 pounds per million Btu of heat input when the heat input to the combustion unit in millions of Btus per hour is equal to or greater than 600," with an averaging time of one hour. *See* 25 Pa. Code § 123.11(3); 25 Pa. Code § 139.12(4).[2] This would require continuous monitoring. However, the current draft permit only requires stack testing once *every five years* to ensure that the Shawville Plant is in compliance with particulate matter emission limits. *See* Draft Permit at 28 (Boiler #1), 36 (Boiler #2), 44 (Boiler #3), and 52 (Boiler #4). Such extremely periodic monitoring simply cannot assure compliance with particulate matter emission limits.

The Draft Permit Includes Inadequate Compliance Assurance Monitoring Requirements Regarding Shawville's Particulate Matter

Although the draft permit does include requirements for continuous opacity monitoring, the implementation of opacity monitoring as contemplated in the draft permit will not adequately assure compliance with particulate matter emission limits.

Under its Compliance Assurance Monitoring ("CAM") rules, the EPA requires that major source owners "establish . . . appropriate range(s) . . . for the selected indicator(s) such that operation within the ranges provides a reasonable assurance of ongoing compliance with emission limitations or standards." 40 C.F.R. § 64.3(a)(2); *see also* 42 U.S.C. § 7414(a)(3) (authorizing the EPA to "require enhanced monitoring and submission of compliance certifications" from major sources). CAM also imposes an affirmative requirement on each major source to bring its emissions within the acceptable range when the source falls outside the acceptable range. *See* 40 C.F.R. § 64.7(d). Specifically, the source must "restore operation of the pollutant-specific emissions unit

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[2] All four boilers at the Shawville Plant have heat inputs in excess of 600 million Btus per hour.

(including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable . . . ." *Id.*

The draft permit contemplates opacity monitoring as the methodology to ensure continuous compliance with both the Plant's opacity limits and with separate particulate matter emissions limits. This is improper in this case for three reasons.

First, opacity monitoring fails to adequately capture secondary particulate matter emissions, i.e., the particulate matter that condenses from vapor *after* leaving the exhaust stack. Merely monitoring opacity does not, therefore, provide assurance that overall particulate matter emissions for the Shawville Plant are within the limits prescribed by the SIP, as required by 40 C.F.R. § 64.3(a)(2). Mere opacity monitoring, while salutary and an essential part of ensuring overall source compliance with the Clean Air Act, is inadequate for ensuring compliance with particulate matter emission limitations.

Instead, continuous emissions monitoring systems ("CEMS") for fine particles (as $PM_{2.5}$) and for particulate matter in general should be required in any final permit. There are many facilities that operate particulate matter CEMS and have demonstrated that the systems are reliable and accurate. These include, for example, the Tampa Electric power plant (Florida) (see attached Tampa Electric Company Consent Decree at 20-21, attached hereto as Exhibit 1), Eli Lilly Corporation (Indiana), and the U.S. Department of Energy (Tennessee). *See* "Current Knowledge of Particulate Matter (PM) Continuous Emission Monitoring," EPA-454/R-00-039, September 2000, at viii and 4-2 to 4-5, attached hereto as Exhibit 2. The EPA has also secured commitments from up to 30 existing coal-fired utility installations to install particulate matter CEMS within the next few years. For example, American Electric Power Company and SWEPCO have agreed to install particulate matter CEMS on existing coal-fired power plants. *See* Public Citizen Consent Decree at 5, attached hereto as Exhibit 3. Moreover, particulate matter CEMS have been required in Pennsylvania, too. *See, e.g.*, Citizens for Pennsylvania's Future Consent Decree (requiring particulate matter CEMS for the Bruce Mansfield plant), attached hereto as Exhibit 4; *see also* DEP Consent Order and Agreement (same), attached hereto as Exhibit 5. There is no reason why the Shawville Plant should not be required to implement similar systems.

The final permit should require CEMS for particulate matter for each of the Shawville Plant's boilers. Particulate matter (PM_{10} and $PM_{2.5}$) poses serious health concerns. Particulate matter contains a mixture of harmful substances, including, but not limited to toxic metals (antimony, arsenic, barium, beryllium, cadmium, chromium VI, copper, lead, mercury, manganese, nickel, selenium, silver, vanadium, zinc) and various oxidized metallic compounds; inorganic acidic compounds due to chlorine and fluorine in the coal including hydrochloric acid (HCl) and hydrofluoric acid (HF); sulfur compounds from the sulfur in the coal, including sulfur dioxide (SO_2), sulfuric acid (H_2SO_4), sulfurous acid (H_2SO_3) and sulfur trioxide (SO_3); nitrogen compounds including but not limited to nitric acid (HNO_3) and nitrous acid (HNO_2); carbon-containing products of incomplete combustion such as Polycyclic Aromatic Hydrocarbons (PAHs); radon including its radioactive carcinogenic byproducts Polonium 210 and Lead 210; ammonia (NH_3); and other chemicals.

In comments submitted in March 2005 for the Robinson Power Company PSD Application and Draft Plan Approval, for a proposed 270 megawatt waste coal fired, circulating fluidized bed (CFB) boiler facility at Robinson Township, Pennsylvania, the EPA noted that:

> The proposed plan approval requires annual stack testing to assure compliance with the particulate matter emission limits from the CFB and its associated fabric-filter baghouse. In light of the evolution of CEMS systems for particulate matter, EPA is strongly urging the requirement to install and operate a particulate matter CEMS at the proposed facility. Currently, there are several facilities that operate PM CEMS and have demonstrated that the systems are reliable and accurate. These are 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. It is fair to assume that the state of technology for PM CEMS will be even further evolved by the time the proposed Robinson Power facility begins operation. Further, the facility will be required to establish a compliance assurance monitoring plan (CAM) as part of its title V operating permit and the federal CAM regulations strongly encourage reliance on continuous monitoring systems as a means for assuring compliance.[3]

Common types of particulate matter CEMS were described by the EPA *a decade ago* (which only bolsters the contention that particulate matter CEMS technology is widely available) in "Current Knowledge of Particulate Matter (PM) Continuous Emission Monitoring," EPA-454/R-00-039, September 2000. *See* Exhibit 2. That document describes at least two technologies that should be considered for continuous particulate matter monitoring at the Shawville Plant: Light Scattering (an emitted light beam passes through a defined sample volume); and Acoustic Energy (shock waves caused by the impact of particles with a probe inserted into the flow are used to measure the particulate concentration). The technology is available, and, because it is the only technology that "provides a reasonable assurance of ongoing compliance with emission limitations or standards" 40 C.F.R. § 64.3(a)(2), it must be implemented, in accordance with EPA's performance specification 11, attached hereto as Exhibit 6. At the very least, quarterly stack tests for condensable particulate matter conducted pursuant to the final test method published in 75 Fed. Reg. 801118 (Dec. 21, 2010).

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[3] These comments were submitted to DEP on or about March 11, 2005, and should be located in DEP's files. The Sierra Club has submitted a records request to DEP seeking a copy of these comments, but has not yet received a copy.

Second, while the draft permit contemplates that continuous opacity monitors will be used to determine continuous compliance with the Plant's separate opacity limits, it fails to specify opacity levels and corresponding particulate matter levels. Stated another way, if DEP considers opacity as a surrogate for particulate matter—which again does not address the issue of condensable particulate matter—then, in the very least, the final permit must include a specific provision describing the exact opacity level (expressed as percentage, e.g., 5% or 10% opacity) that corresponds to a particulate matter exceedance. As the draft permit is currently written—without either a particulate matter CEMS or a specific permit condition that pins the PM limit to a specific corresponding opacity level—DEP must treat any exceedance of the applicable opacity standards as conclusive evidence of an exceedance of the Plant's applicable particulate matter limit.

The final Title V permit issued for the Shawville Plant should, accordingly, require continuous emissions monitoring (CEMs) for particulate matter that complies with EPA's performance specification 11. This is necessary to ensure compliance with the SIP as regards filterable particulate matter. Second, the CEMS must also ensure that condensable particulate matter is monitored as discussed above. Third, the permit must have provisions that tie specific opacity levels to particulate matter levels so that violations of opacity standards can readily be translated to violations of the correlating particulate matter standards. Finally, a final permit must contain at the very least quarterly stack tests for condensable particulate matter conducted pursuant to the final test method published in 75 Fed. Reg. 801118 (Dec. 21, 2010).

The Draft Permit Lacks A Compliance Schedule for Remedying Significant, Ongoing Violations of the Clean Air Act

A Title V permit must include a compliance schedule for "requirements for which the source is not in compliance at the time of the permit issuance." 40 C.F.R. § 70.5(c)(8)(iii)(C); *id.* at § 70.6(c)(3) (requiring draft permits to contain a "schedule of compliance consistent with §70.5(c)(8)"); *see also* 42 U.S.C. § 7661c(a) ("Each permit issued under this subchapter shall include . . . a schedule of compliance"). Accordingly, permits must contain a "description of the compliance status of the source," a "a narrative description of how the source will achieve compliance" with requirements for which it is in noncompliance, and a "schedule of compliance for sources that are not in compliance with all applicable requirements at the time of permit issuance." 40 C.F.R. § 70.5(c)(8); *id.* at § 70.6(c)(3). The schedule itself must "include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the source will be in noncompliance at the time of permit issuance." 40 C.F.R. § 70.5(c)(8)(ii)(C); *id.* at § 70.6(c)(3). Additionally, compliance schedules are intended to be rigorous: they "shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject." *Id.* As such, Title V permits must spell out enforceable, specific steps to be taken by sources with histories of noncompliance in order to return those sources to compliance.

The Shawville Plant has a history of chronic opacity violations for which it has been fined in the past.[4] *See, e.g.*, 2008 Continuous Source Quarterly Monitoring Reports; January 14, 2009 Notice of Violation; March 17, 2009 Correspondence Re: Penalty Agreement; June 10, 2009 Consent Assessment of Civil Penalty; and Quarter 2 2010 Continuous Source Monitoring Report, attached hereto as Exhibits 7, 8, 9, 10, and 11 respectively. These violations are ongoing and must be addressed in the final Title V permit.

The Draft Permit Fails to Ensure that the Shawville Plant Will Not Cause or Contribute to Violations of the New One-Hour NAAQS for SO_2

On June 22, 2010, EPA amended the SO_2 NAAQS by revoking the 24-hour and annual standards and establishing a new one-hour standard. 75 Fed. Reg. 35530 (June 22, 2010) (effective August 23, 2010). Although Pennsylvania has not yet had the opportunity to update the state regulations to reflect the revised SO_2 NAAQS, it will have to at the least adopt the new one-hour SO_2 NAAQS in the near future because state law must be at least as stringent as federal law. *See* 42 U.S.C. § 7416 (noting that states "may not adopt or enforce any emission standard or limitation which is less stringent than the standard or limitation" under federal law). The Shawville Plant draft permit should be revised to include the new one-hour SO_2 NAAQS in the provisions that preclude the plant from causing or contributing to ambient air quality exceedences.

The Draft Permit Fails to Ensure that the Shawville Plant Will Not Cause or Contribute to Violations of the New One-Hour NAAQS for NO_2

Similarly, on February 9, 2010, EPA amended the NO_2 NAAQS by establishing a new one-hour standard. 75 Fed. Reg. 6474 (February 9, 2010) (effective April 12, 2010). Although Pennsylvania has not yet had the opportunity to update the state regulations to reflect the revised NO_2 NAAQS, it will have to at the least adopt the new one-hour NO_2 NAAQS in the near future because state law must be at least as stringent as federal law. *See* 42 U.S.C. § 7416 (noting that states "may not adopt or enforce any emission standard or limitation which is less stringent than the standard or limitation" under federal law). As with the new SO_2 NAAQS, the Shawville Plant draft permit should be revised to include the new one-hour NO_2 NAAQS in the provisions that preclude the plant from causing or contributing to ambient air quality exceedences.

The Draft Permit Does Not Provide Sufficient Specificity in its Requirements for Continuous Emissions Monitoring for SO_2, CO_2, and NO_x

Finally, the draft permit as currently written does not provide sufficient detail in requiring continuous emissions monitoring for the pollutants SO_2, CO_2, and NO_x. Regulations promulgated by the EPA govern the types of data to be collected by CEMS. *See* 40 C.F.R. § 75.10. For SO_2, the CEMS must incorporate "an automated data acquisition and handling system" to measure "concentration (in ppm)" as well as "volumetric gas flow

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[4] These include sanctions for failures to timely report opacity violations.

(in scfh)," and "mass emission." *Id.* at § 75.10(a)(1). For CO_2, the CEMS must likewise incorporate "an automated data acquisition and handling system" to measure "concentration (in ppm or percent)," as well as "volumetric gas flow (in scfh)," and "mass emissions (in tons/hr)." *Id.* at § 75.10(a)(3). Finally, for NO_x, the CEMS must include an automated data acquisition and handling system to measure "concentration (in ppm)" and "emission rate (in lb/mmBtu)." *Id.* at § 75.10(a)(2).

However, the draft permit does not contain this level of detail, and instead merely calls for continuous emissions monitoring. Any final permit should make clear that the Shawville Plant is required to comply with the data collection provisions spelled out in 40 C.F.R. § 75.10.[5]

C. Conclusion

For the foregoing reasons, the draft permit is insufficient, and should be amended as described above, and re-noticed for public comment before any final permit issues.

Sincerely,

Zachary M. Fabish
The Sierra Club
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Washington, DC 20002
zachary.fabish@sierraclub.org
(202) 675-7917

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[5] These concerns are shared by the EPA. *See* November 29, 2010 Correspondence from Emlyn Vélez-Rosa to Thomas Calhoun, attached hereto as Exhibit 12.

Pennsylvania Department of Environmental Protection

Rachel Carson State Office Building
P.O. Box 8468
Harrisburg, PA 17105-8468
December 15, 2010

Bureau of Air Quality 717-787-9702

Ms. Danielle L. Gagne
Law Clerk
Sierra Club Environmental Law Program
408 C Street NE
Washington, DC 20002

Re: Request for an Extension of Comment Period on the Renewal of the Title V Operating Permit for the Shawville Generation Station (TVOP-17-00001)

Dear Ms. Gagne:

This letter responds to your electronically transmitted letter on December 3, 2010, requesting that the Department of Environmental Protection (DEP) grant Sierra Club a 30-day extension of comment period to provide comments on the renewal of the Title V Operating Permit for the RRI Energy Mid-Atlantic Power Holdings, LLC Shawville Generation Station in Bradford Township, Clearfield County.

As you know, DEP is obligated under 25 *Pa. Code* Sections 127.424 and 127.521 (relating to public notice and additional public participation provisions) to provide at least a 30-day public comment period in accordance with the notice requirements specified in 25 *Pa. Code* Sections 127.424 and 127.521 (relating to public notice and additional public participation provisions). Therefore, notice of DEP's intent to issue the renewal of the Title V Operating Permit for the Shawville Generation Station was published in the *Pennsylvania Bulletin* on October 30, 2010, at 40 *Pa. B.* 6306, and November 20, 2010, at 40 *Pa. B.* 6705; the latest comment period will end on December 20, 2010.

While DEP has provided a "sufficient opportunity" for the submissions of comments during the public comment period, it is my understanding that you intend to review DEP's files on the Shawville facility on December 16, 2010. Therefore, a 15-day extension of the comment period is granted for the completion of your comments following your review of the files. To this end, please ensure that your comments on the renewal of the Title V Operating Permit for the Shawville Generation Station are submitted to Mr. Muhammad Zaman, Environmental Program Manager, in the DEP Northcentral Regional Office by close of business on January 4, 2011.

Thank you for bringing this request to my attention. Should you have any questions or need additional information, please contact me by e-mail at jeepps@state.pa.us or by telephone at 717-787-9702. You may also contact Dawn Herb by e-mail at dherb@state.pa.us or by telephone at 570-321-6568.

Sincerely,

Joyce E. Epps
Director

Final Regulatory Impact Analysis (RIA) for the SO_2 National Ambient Air Quality Standards (NAAQS)

June 2010

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Health and Environmental Impact Division
Air Benefit-Cost Group
Research Triangle Park, North Carolina

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Executive Summary

ES.1 Overview

This Regulatory Impact Analysis (RIA) provides illustrative estimates of the incremental costs and monetized human health benefits of attaining a revised short-term Sulfur Dioxide (SO_2) National Ambient Air Quality Standard (NAAQS) within the current monitoring network of 488 SO_2 monitors. Because this analysis only considers counties with an SO_2 monitor, the possibility exists that there may be many more potential nonattainment areas than have been analyzed in this RIA.

This RIA chiefly serves two purposes. First, it provides the public with an estimate of the costs and benefits of attaining a new SO_2 NAAQS. Second, it fulfills the requirements of Executive Order 12866 and the guidelines of OMB Circular A-4. [1] These documents present guidelines for EPA to assess the benefits and costs of the selected regulatory option, as well as one less stringent and one more stringent option. The RIA analyzes the new short-term SO_2 NAAQS of 75 parts per billion (ppb), based on the 3-year average of the 99th percentile of 1-hour daily maximum concentrations. This RIA also analyzes alternative primary standards of 50 and 100 ppb.

This analysis does not estimate the projected attainment status of areas of the country other than those counties currently served by one of the approximately 488 monitors in the current network. It is important to note that the final rule requires a monitoring network comprised of monitors sited at locations of expected maximum hourly concentrations, and also provides for nonattainment designations using air quality modeling near large stationary sources. Only about one third of the existing SO_2 network may be source-oriented and/or in the locations of maximum concentration required by the final rule because the current network is focused on population areas and community-wide ambient levels of SO_2. Actual monitored levels using the new monitoring network and/or air quality modeling results near large stationary sources may be higher than levels measured using the existing network. We recognize that once the new requirements are put in place, more areas could find themselves exceeding the new SO_2 NAAQS. However for this RIA analysis, we lack sufficient data to predict which counties might exceed the new NAAQS after implementation of the new monitoring network and modeling requirements. Therefore we lack a credible analytic path to estimating costs and benefits for such a future scenario.

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[1] U.S. Office of Management and Budget. Circular A-4, September 17, 2003. Available at http://www.whitehouse.gov/omb/circulars/a004/a-4.pdf.

In setting primary ambient air quality standards, EPA's responsibility under the law is to establish standards that protect public health, regardless of the costs of implementing a new standard. The Clean Air Act requires EPA, for each criteria pollutant, to set a standard that protects public health with "an adequate margin of safety." As interpreted by the Agency and the courts, the Act requires EPA to create standards based on health considerations only.

The prohibition against the consideration of cost in the setting of the primary air quality standard, however, does not mean that costs or other economic considerations are unimportant or should be ignored. The Agency believes that consideration of costs and benefits is essential to making efficient, cost effective decisions for implementation of these standards. The impacts of cost and efficiency are considered by states during this process, as they decide what timelines, strategies, and policies are most appropriate. This RIA is intended to inform the public about the potential costs and benefits associated with a hypothetical scenario that may result when a new SO_2 standard is implemented, but is not relevant to establishing the standards themselves.

ES.2 Summary of Analytic Approach

This RIA includes several key elements, including specification of baseline SO_2 emissions and concentrations; development of illustrative control strategies to attain the standard in 2020; and analyses of the control costs and health benefits of reaching the various alternative standards. Additional information on the methods employed by the Agency for this RIA is presented below.

Overview of Baseline Emissions Forecast and Baseline SO_2 Concentrations

The baseline emissions and concentrations for this RIA are emissions data from the 2005 National Emissions Inventory (NEI), and baseline SO_2 concentration values from 2005-2007 across the community-wide monitoring network. We used results from community multi-scale air quality model (CMAQ) simulations to calculate the expected reduction in ambient SO_2 concentrations between the 2005 base year and 2020. More specifically, design values (i.e. air quality concentrations at each monitor) were calculated for 2020 using monitored air quality concentrations from 2005 and modeled air quality projections for 2020, countywide emissions inventory data for 2005 and 2006-8, and emissions inventory projections for 2020. These data were used to create ratios between emissions and air quality, and those ratios (relative response factors, or RRFs) were used to estimate air quality monitor design values for 2020. The 2020 baseline air quality estimates revealed that 27 monitors in 24 counties were projected to exceed the 75 ppb NAAQS in 2020.

Development of Illustrative Control Strategies

For each alternative standard, we analyzed the impact that additional emissions controls applied to numerous sectors would have on predicted ambient SO_2 concentrations, incremental to the baseline set of controls. Thus the modeled analysis for a revised standard focuses specifically on incremental improvements beyond the current standards, and uses control options that might be available to states for application by 2020. The hypothetical modeled control strategy presented in this RIA is one illustrative option for achieving emissions reductions to move towards a national attainment of a tighter standard. It is not a recommendation for how a tighter SO_2 standard should be implemented, and states will make decisions regarding implementation strategies once a final NAAQS has been set.

The baseline for this analysis is complicated by the expected issuance of additional air quality regulations. The SO_2 NAAQS is only one of several regulatory programs that are likely to affect EGU emissions nationally in the next several years. We thus expect that EGUs will apply controls in the coming years in response to multiple rules. These include the maximum achievable control technology (MACT) rule for utility boilers, revisions to the Clean Air Interstate Rule, and reconsideration of the Clean Air Mercury Rule. Therefore controls and costs attributed solely to the SO_2 NAAQS in this analysis will likely be needed for compliance with other future rules as well.

The 2020 baseline air quality estimates revealed that 27 monitors in 24 counties were projected to exceed the 75 ppb NAAQS in 2020. We then developed hypothetical control strategies that could be adopted to bring the current highest emitting monitor in each of those counties into attainment with 75 ppb by 2020, as well as hypothetical control strategies for counties exceeding the lower bound analytic target of 50 ppb, and the upper bound analytic target of 100 ppb. Controls for three emissions sectors were included in the control analysis: non-electricity generating unit point sources (nonEGU), area sources (area), and electricity generating unit point sources (EGU). Finally, we note it was not possible, in this analysis, to bring all areas into attainment with alternative standards in all areas using identified engineering controls. For these monitor areas we estimated the cost of unspecified emission reductions.

Analysis of Costs and Benefits

We estimated the benefits and costs for the final NAAQS of 75 ppb, as well as alternative SO_2 NAAQS levels of 50 ppb and 100 ppb (99th percentile). These costs and benefits are associated with an incremental difference in ambient concentrations between a baseline scenario and a pollution control strategy. As indicated in Chapter 4, several areas of the country may not be able to attain some alternative standard using known pollution control methods. Because some areas require substantial emission reductions from unknown sources to attain the various standards, the results are very sensitive to assumptions about the costs of full attainment. For this reason, we provide the full attainment results and the partial attainment results for both benefits and costs.

Benefits

Our benefits analysis estimates the human health benefits for each of the alternative standard levels including benefits related to reducing SO_2 concentrations and the co-benefits of reducing concentrations of fine particulate matter ($PM_{2.5}$). For the SO_2 benefits analysis, we use the Environmental Benefits Mapping and Analysis Program (BenMAP) to estimate the health benefits occurring as a result of implementing alternative SO_2 NAAQS levels. BenMAP has been used extensively in previous RIAs to estimate the health benefits of reducing exposure to various pollutants.

The primary input to the benefits assessment for SO_2 effects is the estimated changes in ambient air quality expected to result from a simulated control strategy or attainment of a particular standard. CMAQ projects both design values at SO_2 monitors and air quality concentrations at 12 km by 12 km grid cells nationwide. To estimate the benefits of fully attaining the standards in all areas, EPA employed the “monitor rollback” approach to approximate the air quality change resulting from just attaining alternative SO_2 NAAQS at each design value monitor. Under this approach, we use data from the existing SO_2 monitoring network and the inverse distance-squared variant of the Veronoi Neighborhood Averaging (VNA) interpolation method to adjust the air quality modeled concentrations such that each area just attains the target NAAQS levels.

We quantified SO_2-related health endpoints for which the SO_2 ISA provides the strongest evidence of an effect. In this analysis, we only estimated the benefits for those endpoints with sufficient evidence to support a quantified concentration-response relationship using the information presented in the SO_2 ISA, which contains an extensive literature review for several health endpoints related to SO_2 exposure. Based on our review of this information, we quantified three short-term morbidity endpoints that the SO_2 ISA identified as “sufficient to infer a likely causal relationship”: asthma exacerbation, respiratory-related emergency department visits, and respiratory-related hospitalizations. We then selected concentration-response functions and valuation functions based on criteria detailed in chapter 5. The valuation functions, ambient concentrations, and population data in the monitor areas are combined in BenMAP to provide the benefits estimates for this analysis. In this analysis, we decided not to quantify the premature mortality from SO_2 exposure in this analysis despite evidence suggesting a positive association. As the literature continues to evolve, we may revisit this decision in future benefits assessment for SO_2.

In addition, because SO_2 is also a precursor to $PM_{2.5,}$ reducing SO_2 emissions in the projected non-attainment areas will also reduce $PM_{2.5}$ formation, human exposure, and the incidence of $PM_{2.5}$-related health effects. In this analysis, we estimated the co-benefits of reducing $PM_{2.5}$ exposure for the alternative standards. Due to analytical limitations, it was not possible to provide a comprehensive estimate of $PM_{2.5}$-related benefits. Instead, we used the "benefit-per-ton" method to estimate these benefits. The $PM_{2.5}$ benefit-per-ton estimates provide the total monetized human health benefits (the sum of premature mortality and premature morbidity) of reducing one ton of $PM_{2.5}$ from a specified source. EPA has used these estimates in previous RIAs, including the recent NO_2 NAAQS RIA.

These estimates reflect EPA's most current interpretation of the scientific literature and are consistent with the methodology used for the proposal RIA. These benefits are incremental to an air quality baseline that reflects attainment with the 2008 ozone and 2006 $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS). More than 99% of the total dollar benefits are attributable to reductions in $PM_{2.5}$ exposure resulting from SO_2 emission controls. Higher or lower estimates of benefits are possible using other assumptions; examples of this are provided in Figure 5.1 for the selected standard of 75 ppb. Methodological limitations prevented EPA from quantifying the impacts to, or monetizing the benefits from several important benefit categories, including ecosystem effects from sulfur deposition, improvements in visibility, and materials damage. Other direct benefits from reduced SO_2 exposure have not been quantified, including reductions in premature mortality.

Costs

Consistent with our development of the illustrative control strategies described above, our analysis of the costs associated with the range of alternative NAAQS focuses on SO_2 emission controls for electric generating units (EGU) and nonEGU stationary and area sources. EGU, nonEGU and area source controls largely include measures from the Control Strategy Tool (CoST), and the AirControlNET control technology database. For these sources, we estimated costs based on the cost equations included in AirControlNET.

As indicated in the above discussion on illustrative control strategies, implementation of the SO_2 control measures identified from AirControlNET and other sources does not result in attainment with the selected NAAQS in several areas. In these areas, additional unspecified emission reductions might be necessary to reach some alternative standard levels. In order to bring these monitor areas into attainment, we calculated controls costs using a fixed cost per ton approach similar to that used in the ozone RIA analysis. We recognize that a single fixed cost of control of $15,000 per ton of emissions reductions does not account for the significant emissions cuts that are necessary in some areas, and so its use provides an estimate that is likely to differ from actual future costs.

ES.3 Results of Analysis

Air Quality

Table ES.1 presents the number of monitors and counties exceeding the various target NAAQS levels in 2020 prior to control, out of 229 monitors from which a full set of data were available for this analysis.

Table ES.1. Number of monitors and counties projected to exceed 50, 75, and 100 ppb alternative NAAQS target levels in 2020.

Alternative standard (ppb)	Number of monitors	Number of counties
50	71	56
75	27	24
100	11	9

Table ES.2 presents the emission reductions achieved through applying identical control measures, both by sector and in total. As this table reveals, a majority of the emission reductions would be achieved through EGU emission controls.

Table ES.2: Emission Reductions from Identified Controls in 2020 in Total and by Sector (Tons)[a] for Each Alternative Standard

	50 ppb	75 ppb	100 ppb
Total Emission Reductions from Identified Controls[b]	800,000	370,000	190,000
EGUs	540,000	260,000	110,000
Non-EGUs	250,000	110,000	79,000
Area Sources	15,000	200	100

[a] All estimates rounded to two significant figures. As such, totals may not sum down columns.

[b] These values represent emission reductions for the identified control strategy analysis. There were locations not able to attain the alternative standard being analyzed with identified controls only.

Table ES.3 shows the emission reductions needed beyond identified controls for counties to attain the alternative standards being analyzed.

Table ES.3: Total Emission Reductions and those from Extrapolated Controls in 2020 in Total and by Sector (Tons)[a] for Each Alternative Standard

	50 ppb	75 ppb	100 ppb
Total Emission Reductions from Identified and Unidentified Controls	920,000	350,000	170,000
Total Emission Reductions from Unidentified Controls	110,000	33,000	18,000
Unidentified Reductions from EGUs	33,000	5,000	-
Unidentified Reductions from non-EGUs	54,000	22,000	15,000
Unidentified Reductions from Area Sources	19,000	6,400	3,000

[a] All estimates rounded to two significant figures.

Benefit and Cost Estimates

When estimating the SO_2- and $PM_{2.5}$-related human health benefits and compliance costs in Table ES.4 below, EPA applied methods and assumptions consistent with the state-of-the-science for human health impact assessment, economics and air quality analysis. EPA applied its best professional judgment in performing this analysis and believes that these estimates provide a reasonable indication of the expected benefits and costs to the nation of the selected SO_2 standard and alternatives considered by the Agency. The Regulatory Impacts Analysis (RIA) available in the docket describes in detail the empirical basis for EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below.

EPA's 2009 Integrated Science Assessment for Particulate Matter concluded, based on the scientific literature, that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship. Nonetheless, consistent with historical practice and our commitment to characterizing the uncertainty in our benefits estimates, EPA has included a sensitivity analysis with an assumed threshold in the PM-mortality health impact function in the RIA. EPA has included a sensitivity analysis in the RIA to help inform our understanding of the health benefits which can be achieved at lower air quality concentration levels. While the primary estimate and the sensitivity analysis are not directly comparable, due to differences in population data and use of different analysis years, as well as the difference in the assumption of a threshold in the sensitivity analysis, comparison of the two results provide a rough sense of the proportion of the health benefits that occur at lower $PM_{2.5}$ air quality levels. Using a threshold of 10 $\mu g/m^3$ is an arbitrary choice (EPA could have assumed 6, 8, or 12 µg/m3 for the sensitivity analysis). Assuming a threshold of 10 $\mu g/m^3$, the sensitivity analysis shows that roughly one-third of the benefits occur at air quality levels below that threshold. Because the primary estimates reflect EPA's current methods and data, EPA notes that caution should be exercised when comparing the results of the primary and sensitivity analyses. EPA appreciates the value of sensitivity analyses in highlighting the uncertainty in the benefits estimates and will continue to work to refine these analyses, particularly in those instances in which air quality modeling data are available.

Table ES.4 shows the results of the cost and benefits analysis for each standard alternative. As indicated above, implementation of the SO_2 control measures identified from AirControlNET and other sources does not result in attainment with the all target NAAQS levels in several areas. In these areas, additional unspecified emission reductions might be necessary to reach some alternative standard levels. The first part of the table, labeled *Partial attainment (identified controls)*, shows only those benefits and costs from control measures we were able to identify. The second part of the table, labeled *Unidentified Controls*, shows only additional benefits and costs resulting from unidentified controls. The third part of the table, labeled *Full attainment*, shows total benefits and costs resulting from both identified and unidentified controls. It is important to emphasize that we were able to identify control measures for a significant portion of attainment for many of those counties that would not fully attain the target NAAQS level with identified controls. Note also that in addition to separating full and partial attainment, the table also separates the portion of benefits associated with reduced SO_2 exposure (i.e., SO_2 benefits) from the additional benefits associated with reducing SO_2 emissions, which are precursors to $PM_{2.5}$ formation – (i.e., the $PM_{2.5}$ co-benefits). For instance, for the selected standard of 75 ppb, $2.2 million in benefits are associated with reduced SO_2 exposure while $15 billion to $37 billion are associated with reduced $PM_{2.5}$ exposure.

Table ES.4: Monetized Benefits and Costs to Attain Alternate Standard Levels in 2020 (millions of 2006$)[a]

		# Counties Fully Controlled	Discount Rate	Monetized SO_2 Benefits	Monetized $PM_{2.5}$ Co-Benefits [c,d]	Costs	Net Benefits
Partial Attainment (identified controls)	**50 ppb**	40	3%	-[b]	$30,000 to $74,000	$2,600	$27,000 to $71,000
			7%		$28,000 to $67,000		$25,000 to $64,000
	75 ppb	20	3%	-[b]	$14,000 to $35,000	$960	$13,000 to $34,000
			7%		$13,000 to $31,000		$12,000 to $30,000
	100 ppb	6	3%	-[b]	$6,900 to $17,000	$470	$6,400 to $17,000
			7%		$6,200 to $15,000		$5,700 to $15,000
Unidentified Controls	**50 ppb**	16	3%	-[b]	$4,000 to $9,000	$1,800	$2,200 to $7,200
			7%		$3,000 to $8,000		$1,200 to $6,200
	75 ppb	4	3%	-[b]	$1,000 to $3,000	$500	$500 to $1,500
			7%		$1,000 to $3,000		$500 to $2,500
	100 ppb	3	3%	-[b]	$500 to $1,000	$260	$240 to $740
			7%		$500 to $1,000		$240 to $740
Full Attainment	**50 ppb**	56	3%	$8.50	$34,000 to $83,000	$4,400	$30,000 to $79,000
			7%		$31,000 to $75,000		$27,000 to $71,000
	75 ppb	24	3%	$2.20	$15,000 to $37,000	$1,500	$14,000 to $36,000
			7%		$14,000 to $34,000		$13,000 to $33,000
	100 ppb	9	3%	$0.60	$7,400 to $18,000	$730	$6,700 to $17,000
			7%		$6,700 to $16,000		$6,000 to $15,000

[a] Estimates have been rounded to two significant figures and therefore summation may not match table estimates.

[b] The approach used to simulate air quality changes for SO_2 did not provide the data needed to distinguish partial attainment benefits from full attainment benefits from reduced SO_2 exposure. Therefore, a portion of the SO_2 benefits is attributable to the known controls and a portion of the SO_2 benefits are attributable to the unidentified controls. Because all SO_2-related benefits are short-term effects, the results are identical for all discount rates.

[c] Benefits are shown as a range from Pope et al (2002) to Laden et al. (2006). Monetized benefits do not include unquantified benefits, such as other health effects, reduced sulfur deposition, or improvements in visibility.

[d] These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. Reductions in SO_2 emissions from multiple sectors to meet the SO_2 NAAQS would primarily reduce the sulfate fraction of $PM_{2.5}$. Because this rule targets a specific particle precursor (i.e., SO_2), this introduces some uncertainty into the results of the analysis.

ES.4. Caveats and Limitations

Air Quality, Emissions, and Control Strategies

The estimates of emission reductions associated with the control strategies described above are subject to important limitations and uncertainties. We summarize these limitations as follows:

- *Actual State Implementation Plans May Differ from our Simulation*: In order to reach attainment with the proposed NAAQS, each state will develop its own implementation plan implementing a combination of emissions controls that may differ from those simulated in this analysis. This analysis therefore represents an approximation of the emissions reductions that would be required to reach attainment and should not be treated as a precise estimate.

- *Use of Existing CMAQ Model Runs*: This analysis represents a screening level analysis. We did not conduct new regional scale modeling specifically targets to SO_2; instead we relied upon impact ratios developed from model runs used in the analysis underlying the $PM_{2.5}$ NAAQS.

- *Unidentified controls*: We have limited information on available controls for some of the monitor areas included in this analysis. For a number of small non-EGU and area sources, there is little or no information available on SO_2 controls.

Costs

- We do not have sufficient information for all of our known control measures to calculate cost estimates that vary with an interest rate. We are able to calculate annualized costs at an interest rate other than 7% (e.g., 3% interest rate) where there is sufficient information—available capital cost data, and equipment life—to annualize the costs for individual control measures. For the vast majority of nonEGU point source control measures, we do have sufficient capital cost and equipment life data for individual control measures to prepare annualized capital costs using the standard capital recovery factor. Hence, we are able to provide annualized cost estimates at different interest rates for the point source control measures.

- There are some unquantified costs that are not adequately captured in this illustrative analysis. These costs include the costs of federal and State administration of control programs, which we believe are less than the alternative of States developing approvable SIPs, securing EPA approval of those SIPs, and Federal/State enforcement. Additionally, control measure costs referred to as “no cost” may require limited government agency resources for administration and oversight of the program not included in this analysis; those costs are generally outweighed by the saving to the industrial, commercial, or private sector. The Agency also did not consider transactional costs and/or effects on labor supply in the illustrative analysis.

Benefits

Although we strive to incorporate as many quantitative assessments of uncertainty, there are several aspects for which we are only able to address qualitatively. These aspects are important factors to consider when evaluating the relative benefits of the attainment strategies for each of the alternative standards:

- The 12 km CMAQ grid, which is the air quality modeling resolution, may be too coarse to accurately estimate the potential near-field health benefits of reducing SO_2 emissions. These uncertainties may under- or over-estimate benefits.
- The interpolation techniques used to estimate the full attainment benefits of the alternative standards contributed some uncertainty to the analysis. The great majority of benefits estimated for the various standard alternatives were derived through interpolation. As noted previously in this chapter, these benefits are likely to be more uncertain than if we had modeled the air quality scenario for both SO_2 and $PM_{2.5}$. In general, the VNA interpolation approach may under-estimate benefits because it does not account for the broader spatial distribution of air quality changes that may occur due to the implementation of a regional emission control program.
- There are many uncertainties associated with the health impact functions used in this modeling effort. These include: within study variability (the precision with which a given study estimates the relationship between air quality changes and health effects); across study variation (different published studies of the same pollutant/health effect relationship typically do not report identical findings and in some instances the differences are substantial); the application of C-R functions nationwide (does not account for any relationship between region and health effect, to the extent that such a relationship exists); extrapolation of impact functions across population (we assumed that certain health impact functions applied to age ranges broader than that considered in the original epidemiological study); and various uncertainties in the C-R function,

including causality and thresholds. These uncertainties may under- or over-estimate benefits.

- Co-pollutants present in the ambient air may have contributed to the health effects attributed to SO_2 in single pollutant models. Risks attributed to SO_2 might be overestimated where concentration-response functions are based on single pollutant models. If co-pollutants are highly correlated with SO_2, their inclusion in an SO_2 health effects model can lead to misleading conclusions in identifying a specific causal pollutant. Because this collinearity exists, many of the studies reported statistically insignificant effect estimates for both SO_2 and the co-pollutants; this is due in part to the loss of statistical power as these models control for co-pollutants. Where available, we have selected multipollutant effect estimates to control for the potential confounding effects of co-pollutants; these include NYDOH (2006), Schwartz et al. (1994) and O'Connor et al. (2008). The remaining studies include single pollutant models.
- This analysis is for the year 2020, and projecting key variables introduces uncertainty. Inherent in any analysis of future regulatory programs are uncertainties in projecting atmospheric conditions and source level emissions, as well as population, health baselines, incomes, technology, and other factors.
- This analysis omits certain unquantified effects due to lack of data, time and resources. These unquantified endpoints include other health effects, ecosystem effects, and visibility. EPA will continue to evaluate new methods and models and select those most appropriate for estimating the benefits of reductions in air pollution. Enhanced collaboration between air quality modelers, epidemiologists, toxicologists, ecologists, and economists should result in a more tightly integrated analytical framework for measuring benefits of air pollution policies.
- $PM_{2.5}$ co-benefits represent a substantial proportion of total monetized benefits (over 99% of total monetized benefits), and these estimates are subject to a number of assumptions and uncertainties.
    a. $PM_{2.5}$ co-benefits were derived through benefit per-ton estimates, which do not reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors that might lead to an over-estimate or under-estimate of the actual benefits of controlling directly emitted fine particulates.
    b. We assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because $PM_{2.5}$ produced via transported precursors emitted from EGUs may differ significantly from direct $PM_{2.5}$ released from diesel engines and other industrial sources, but no clear scientific grounds exist for supporting differential effects estimates by particle type.

c. We assume that the health impact function for fine particles is linear down to the lowest air quality levels modeled in this analysis. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of $PM_{2.5,}$ including both regions that are in attainment with fine particle standard and those that do not meet the standard down to the lowest modeled concentrations.

d. To characterize the uncertainty in the relationship between $PM_{2.5}$ and premature mortality (which typically accounts for 85% to 95% of total monetized benefits), we include a set of twelve estimates based on results of the expert elicitation study in addition to our core estimates. Even these multiple characterizations omit the uncertainty in air quality estimates, baseline incidence rates, populations exposed and transferability of the effect estimate to diverse locations. As a result, the reported confidence intervals and range of estimates give an incomplete picture about the overall uncertainty in the $PM_{2.5}$ estimates. This information should be interpreted within the context of the larger uncertainty surrounding the entire analysis. For more information on the uncertainties associated with $PM_{2.5}$ co-benefits, please consult the $PM_{2.5}$ NAAQS RIA (Table 5.5).

While the monetized benefits of reduced SO_2 exposure appear small when compared to the monetized benefits of reduced $PM_{2.5}$ exposure, readers should not necessarily infer that the total monetized benefits of attaining a new SO_2 standard are minimal. For this rule, the monetized $PM_{2.5}$ co-benefits represent over 99% of the total monetized benefits. This result is consistent with other recent RIAs, where the $PM_{2.5}$ co-benefits represent a large proportion of total monetized benefits. This result is amplified in this RIA by the decision not to quantify SO_2-related premature mortality and other morbidity endpoints due to the uncertainties associated with estimating those endpoints. Studies have shown that there is a relationship between SO_2 exposure and premature mortality, but that relationship is limited by potential confounding. Because premature mortality generally comprises over 90% of the total monetized benefits, this decision may substantially underestimate the monetized health benefits of reduced SO_2 exposure.

In addition, we were unable to quantify the benefits from several welfare benefit categories. We lacked the necessary air quality data to quantify the benefits from improvements in visibility from reducing light-scattering particles. Previous RIAs for ozone (U.S. EPA, 2008a) and $PM_{2.5}$ (U.S. EPA, 2006a) indicate that visibility is an important benefit category, and previous efforts to monetize those benefits have only included a subset of visibility benefits, excluding benefits in urban areas and many national and state parks. Even this subset accounted for up to 5% of total monetized benefits in the Ozone NAAQS RIA (U.S. EPA, 2008a).

We were also unable to quantify the ecosystem benefits of reduced sulfur deposition because we lacked the necessary air quality data, and the methodology to estimate ecosystem benefits is still being developed. Previous assessments (U.S. EPA, 1999; U.S. EPA, 2005; U.S. EPA, 2009e) indicate that ecosystem benefits are also an important benefits category, but those efforts were only able to monetize a tiny subset of ecosystem benefits in specific geographic locations, such as recreational fishing effects from lake acidification in the Adirondacks. We were also unable to quantify the benefits of decreased mercury methylation from sulfate deposition. Quantifying the relationship between sulfate and mercury methylation in natural settings is difficult, but some studies have shown that decreasing sulfate deposition can also decrease methylmercury.

ES.5. References

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Chapter 1: Introduction and Background

Synopsis

This document estimates the incremental costs and monetized human health benefits of attaining a revised primary sulfur dioxide (SO_2) National Ambient Air Quality Standard (NAAQS) nationwide. This document contains illustrative analyses that consider limited emission control scenarios that states, tribes and regional planning organizations might implement to achieve a revised SO_2 NAAQS. EPA weighed the available empirical data and photochemical modeling to make judgments regarding the proposed attainment status of certain urban areas in the future. According to the Clean Air Act, EPA must use health-based criteria in setting the NAAQS and cannot consider estimates of compliance cost. This Regulatory Impact Analysis (RIA) is intended to provide the public a sense of the benefits and costs of meeting new alternative SO_2 NAAQS, and to meet the requirements of Executive Order 12866 and OMB Circular A-4 (described below in Section 1.2.2).

This RIA provides illustrative estimates of the incremental costs and monetized human health benefits of attaining a revised primary SO_2 National Ambient Air Quality Standard (NAAQS) in 2020 within the current monitoring network[1]. This proposal would add a new short-term (1-hour exposure) standard, in addition to the current annual average standard.

This analysis does not estimate the projected attainment status of areas of the country other than those counties currently served by one of the approximately 488 monitors in the current network. It is important to note that the final rule requires a monitoring network comprised of monitors sited at locations of expected maximum hourly concentrations, and also provides for nonattainment designations using air quality modeling near large stationary sources. Only about one third of the existing SO_2 network may be source-oriented and/or in the locations of maximum concentration required by the final rule because the current network is focused on population areas and community-wide ambient levels of SO_2. Actual monitored levels using the new monitoring network and/or air quality modeling results near large stationary sources may be higher than levels measured using the existing network. We recognize that once the new requirements are put in place, more areas could find themselves exceeding the new SO_2 NAAQS. However for this RIA analysis, we lack sufficient data to predict which counties might exceed the new NAAQS after implementation of the new monitoring network and modeling requirements. Therefore we lack a credible analytic path to estimating costs and benefits for such a future scenario.

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[1] There are 488 monitors. Currently xx monitors (representing xx counties) exceed the final NAAQS in this analysis (75 ppb, 99th percentile daily 1-hour maximum SO_2 concentration).

1.1 Background

Two sections of the Clean Air Act ("Act") govern the establishment and revision of NAAQS. Section 108 (42 U.S.C. 7408) directs the Administrator to identify pollutants which "may reasonably be anticipated to endanger public health or welfare," and to issue air quality criteria for them. These air quality criteria are intended to "accurately reflect the latest scientific knowledge useful in indicating the kind and extent of all identifiable effects on public health or welfare which may be expected from the presence of [a] pollutant in the ambient air." SO_2 is one of six pollutants for which EPA has developed air quality criteria.

Section 109 (42 U.S.C. 7409) directs the Administrator to propose and promulgate "primary" and "secondary" NAAQS for pollutants identified under section 108. Section 109(b)(1) defines a primary standard as "the attainment and maintenance of which in the judgment of the Administrator, based on [the] criteria and allowing an adequate margin of safety, [are] requisite to protect the public health." A secondary standard, as defined in section 109(b)(2), must "specify a level of air quality the attainment and maintenance of which in the judgment of the Administrator, based on [the] criteria, [are] requisite to protect the public welfare from any known or anticipated adverse effects associated with the presence of [the] pollutant in the ambient air." Welfare effects as defined in section 302(h) [42 U.S.C. 7602(h)] include but are not limited to "effects on soils, water, crops, vegetation, manmade materials, animals, wildlife, weather, visibility and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being."

Section 109(d) of the Act directs the Administrator to review existing criteria and standards at 5-year intervals. When warranted by such review, the Administrator is to retain or revise the NAAQS. After promulgation or revision of the NAAQS, the standards are implemented by the States.

1.2 Role of the Regulatory Impact Analysis in the NAAQS Setting Process

1.2.1 Legislative Roles

In setting primary ambient air quality standards, EPA's responsibility under the law is to establish standards that protect public health, regardless of the costs of implementing a new standard. The Clean Air Act requires EPA, for each criteria pollutant, to set a standard that protects public health with "an adequate margin of safety." As interpreted by the Agency and the courts, the Act requires EPA to create standards based on health considerations only.

The prohibition against the consideration of cost in the setting of the primary air quality standard, however, does not mean that costs or other economic considerations are unimportant or should be ignored. The Agency believes that consideration of costs and benefits are essential to making efficient, cost effective decisions for implementation of these standards. The impact of cost and efficiency are considered by states during this process, as they decide what timelines, strategies, and policies make the most sense. This RIA is intended to inform the public about the potential costs and benefits that may result when a new SO_2 standard is implemented, but is not relevant to establishing the standards themselves.

1.2.2 Role of Statutory and Executive Orders

There are several statutory and executive orders that dictate the manner in which EPA considers rulemaking and public documents. This document is separate from the NAAQS decision making process, but there are several statutes and executive orders that still apply to any public documentation. The analysis required by these statutes and executive orders is presented in Chapter 8.

EPA presents this RIA pursuant to Executive Order 12866 and the guidelines of OMB Circular A-4.[2] These documents present guidelines for EPA to assess the benefits and costs of the selected regulatory option, as well as one less stringent and one more stringent option. OMB circular A-4 also requires both a benefit-cost, and a cost-effectiveness analysis for rules where health is the primary effect. Within this RIA we provide a benefit-cost analysis. Methodological and data limitations prevent us from performing a cost-effectiveness analysis and a meaningful more formal uncertainty analysis for this RIA.

The proposal would set a new short-term SO_2 standard based on the 3-year average of the 99th percentile of 1-hour daily maximum concentrations, establishing a new standard within the range of 75 parts per billion (ppb). This RIA analyzes alternative primary standards of 50 ppb, and 100 ppb.

1.2.3 Market Failure or Other Social Purpose

OMB Circular A-4 indicates that one of the reasons a regulation such as the NAAQS may be issued is to address market failure. The major types of market failure include: externality, market power, and inadequate or asymmetric information. Correcting market failures is one reason for regulation, but it is not the only reason. Other possible justifications include

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[2] U.S. Office of Management and Budget. Circular A-4, September 17, 2003, available at <http://www.whitehouse.gov/omb/circulars/a004/a-4.pdf>.

improving the function of government, removing distributional unfairness, or promoting privacy and personal freedom.

An externality occurs when one party's actions impose uncompensated benefits or costs on another party. Environmental problems are a classic case of externality. For example, the smoke from a factory may adversely affect the health of local residents while soiling the property in nearby neighborhoods. If bargaining was costless and all property rights were well defined, people would eliminate externalities through bargaining without the need for government regulation. From this perspective, externalities arise from high transaction costs and/or poorly defined property rights that prevent people from reaching efficient outcomes through market transactions.

Firms exercise market power when they reduce output below what would be offered in a competitive industry in order to obtain higher prices. They may exercise market power collectively or unilaterally. Government action can be a source of market power, such as when regulatory actions exclude low-cost imports. Generally, regulations that increase market power for selected entities should be avoided. However, there are some circumstances in which government may choose to validate a monopoly. If a market can be served at lowest cost only when production is limited to a single producer of local gas and electricity distribution services, a natural monopoly is said to exist. In such cases, the government may choose to approve the monopoly and to regulate its prices and/or production decisions. Nevertheless, it should be noted that technological advances often affect economies of scale. This can, in turn, transform what was once considered a natural monopoly into a market where competition can flourish.

Market failures may also result from inadequate or asymmetric information. Because information, like other goods, is costly to produce and disseminate, an evaluation will need to do more than demonstrate the possible existence of incomplete or asymmetric information. Even though the market may supply less than the full amount of information, the amount it does supply may be reasonably adequate and therefore not require government regulation. Sellers have an incentive to provide information through advertising that can increase sales by highlighting distinctive characteristics of their products. Buyers may also obtain reasonably adequate information about product characteristics through other channels, such as a seller offering a warranty or a third party providing information.

There are justifications for regulations in addition to correcting market failures. A regulation may be appropriate when there are clearly identified measures that can make government operate more efficiently. In addition, Congress establishes some regulatory programs to redistribute resources to select groups. Such regulations should be examined to ensure that they are both effective and cost-effective. Congress also authorizes some regulations to prohibit discrimination that conflicts with generally accepted norms within our society. Rulemaking may also be appropriate to protect privacy, permit more personal freedom or promote other democratic aspirations.

From an economics perspective, setting an air quality standard is a straightforward case of addressing an externality, in this case where entities are emitting pollutants, which cause health and environmental problems without compensation for those suffering the problems. Setting a standard with a reasonable margin of safety attempts to place the cost of control on those who emit the pollutants and lessens the impact on those who suffer the health and environmental problems from higher levels of pollution.

1.2.4 Illustrative Nature of the Analysis

This SO_2 NAAQS RIA is an illustrative analysis that provides useful insights into a limited number of emissions control scenarios that states might implement to achieve a revised SO_2 NAAQS. Because states are ultimately responsible for implementing strategies to meet any revised standard, the control scenarios in this RIA are necessarily hypothetical in nature. They are not forecasts of expected future outcomes. Important uncertainties and limitations are documented in the relevant portions of the analysis.

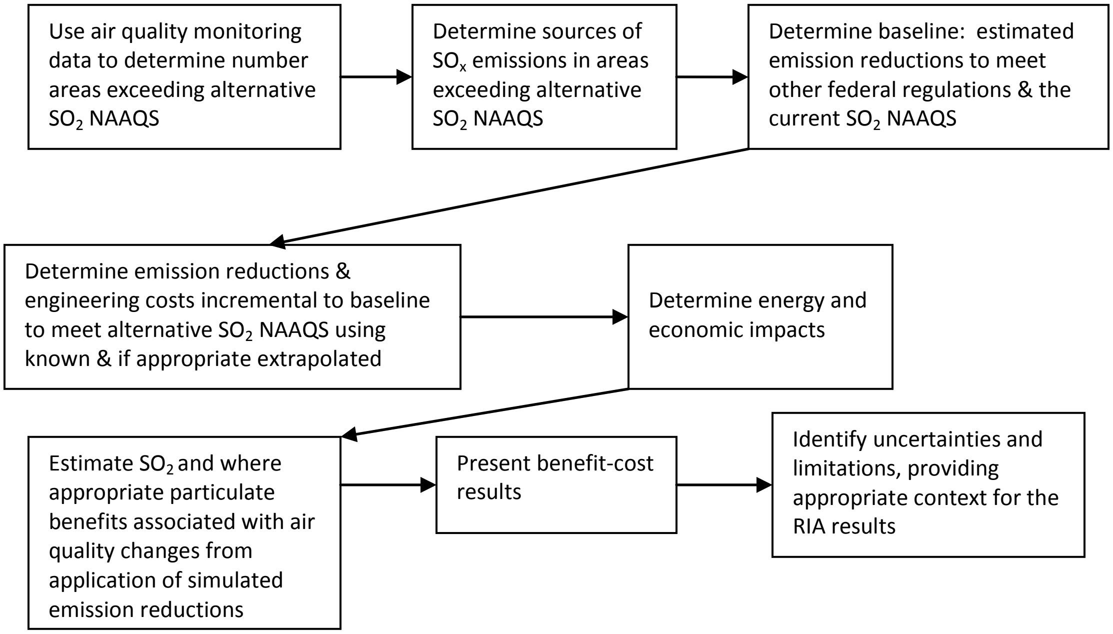
The illustrative goals of this RIA are somewhat different from other EPA analyses of national rules, or the implementation plans states develop, and the distinctions are worth brief mention. This RIA does not assess the regulatory impact of an EPA-prescribed national or regional rule, nor does it attempt to model the specific actions that any state would take to implement a revised SO_2 standard. This analysis attempts to estimate the costs and human and welfare benefits of cost-effective implementation strategies which might be undertaken to achieve national attainment of new standards. These hypothetical strategies represent a scenario where states use one set of cost-effective controls to attain a revised SO2 NAAQS. Because states—not EPA—will implement any revised NAAQS, they will ultimately determine appropriate emissions control scenarios. State implementation plans would likely vary from EPA's estimates due to differences in the data and assumptions that states use to develop these plans.

The illustrative attainment scenarios presented in this RIA were constructed with the understanding that there are inherent uncertainties in projecting emissions and controls. Furthermore, certain emissions inventory, control, modeling and monitoring limitations and uncertainties inhibit EPA's ability to model full attainment in all areas. Despite these limitations, EPA has used the best available data and methods to produce this RIA.

1.3 Overview and Design of the RIA

This Regulatory Impact Analysis evaluates the costs and benefits of hypothetical national strategies to attain several potential revised primary SO_2 standards. The document is intended to be straightforward and written for the lay person with a minimal background in chemistry, economics, and/or epidemiology. Figure 1-1 provides an illustration of the process used to create this RIA.

Figure 1-1: The Process Used to Create this RIA



1.3.1 Baseline and Years of Analysis

The analysis year for this regulatory impact analysis is 2020, which approximates the required attainment year under the Clean Air Act. Many areas will reach attainment of any alternative SO_2 standard before 2020. For purposes of this analysis, we assess attainment by 2020 for all areas. Some areas for which we assume 2020 attainment may in fact need more time to meet one or more of the analyzed standards, while others will need less time. This analysis does not prejudge the attainment dates that will ultimately be assigned to individual areas under the Clean Air Act.

The methodology first estimates what baseline SO_2 levels might look like in 2020 with existing Clean Air Act programs, including application of controls to meet the current SO_2 NAAQS, various maximum achievable control technology (MACT) standards, and then predicts the change in SO_2 levels following the application of additional controls to reach tighter alternative standards. This allows for an analysis of the incremental change between the current standard and alternative standards.

1.3.2 Control Scenarios Considered in this RIA

In this RIA we analyzed the final NAAQS of 75 ppb, as well as hypothetical target NAAQS levels of 50 and 100 ppb. Hypothetical control strategies were developed for each NAAQS level. First, we used outputs from CMAQ model runs to estimate air quality changes that would result from the application of emissions control options that are known to be available to different types of sources in areas with monitoring levels currently exceeding the alternative standards. However, given and the amount of improvement in air quality needed to reach the some standards in some areas, as well as circumstances specific to those areas, it was also expected that applying these known controls would not reduce SO_2 concentrations sufficiently to allow these two areas to reach some standards. In order to bring these monitor areas into attainment, we calculated the cost of unspecified emission reductions by extrapolating from a range of fixed costs per ton of emission control that are generally identified nationally.

1.3.3 Evaluating Costs and Benefits

We applied a two step methodology for estimating emission reductions needed to reach full attainment. First, we quantified the costs associated with applying known controls. Second, we estimated costs of the additional tons of extrapolated emission reductions estimated which were needed to reach full attainment. This methodology enabled us to evaluate nationwide costs and benefits of attaining a tighter SO_2 standard using hypothetical strategies, albeit with substantial additional uncertainty regarding the second step estimates. [3]

To streamline this RIA, this document refers to several previously published documents, including two technical documents EPA produced to prepare for promulgation of the SO_2 NAAQS. The first was the Integrated Science Assessment (ISA) created by EPA's Office of Research and Development (U.S. EPA, 2008), which presented the latest available pertinent information on atmospheric science, air quality, exposure, health effects, and environmental effects of SO_2. The second was the Risk and Exposure Assessment (REA) (U.S. EPA, 2009) for various standard levels. The REA also includes staff conclusions and recommendations to the Administrator regarding potential revisions to the standards.

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[3] Because the secondary SO_2 NAAQS is under development in a separate regulatory process, no additional costs and benefits were calculated in this RIA.

1.4 SO_2 Standard Alternatives Considered

EPA has performed an illustrative analysis of the potential costs and human health and visibility benefits of nationally attaining SO_2 NAAQS of 50, 75, and 100 ppb, assuming a baseline of no additional control beyond the controls expected from rules that are already in place (including the current $PM_{2.5}$ NAAQS), and solely within the bounds of the existing monitoring network. The benefit and cost estimates below are calculated incremental to a 2020 baseline that incorporates air quality improvements achieved through the projected implementation of existing regulations and attainment of the existing PM National Ambient Air Quality Standards (NAAQS). The baseline also includes the MACT program, the clean air interstate rule (CAIR), and implementation of current consent decrees, all of which would help many areas move toward attainment of the SO_2 standard.

1.5 References

U.S. Environmental Protection Agency (U.S. EPA). 1970. Clean Air Act. 40 CFR 50.

U.S. Environmental Protection Agency (U.S. EPA). 2008. Integrated Science Assessment for Sulfur Oxides - Health Criteria (Final Report). National Center for Environmental Assessment, Research Triangle Park, NC. September. Available on the Internet at < http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=198843>.

U.S. Environmental Protection Agency (U.S. EPA). 2009. Risk and Exposure Assessment to Support the Review of the SO_2 Primary National Ambient Air Quality Standards: Final Report. Office of Air Quality Planning and Standards, Research Triangle Park, NC. August. Available on the Internet at <http://www.epa.gov/ttn/naaqs/standards/so2/data/Risk%20and%20Exposure%20Assessment%20to%20Support%20the%20Review%20of%20the%20SO2%20Primary%20National%20Ambient%20Air%20Quality%20Standards-%20Final%20Report.pdf>.

Chapter 2: SO_2 Emissions and Monitoring Data

Synopsis

This chapter describes the available SO_2 emissions and air quality data used to inform and develop the control strategies outlined in this RIA. We first describe data on SO_2 emission sources contained in available EPA emission inventories. We then provide an overview of data sources for air quality measurement. For a more in-depth discussion of SO_2 emissions and air quality data, see the Integrated Science Assessment for the SO_2 NAAQS.[1]

2.1 Sources of SO_2

In order to estimate risks associated with SO_2 exposure, principal sources of the pollutant must first be characterized because the majority of human exposures are likely to result from the release of emissions from these sources. Anthropogenic SO_2 emissions originate chiefly from point sources, with fossil fuel combustion at electric utilities (~66%) and other industrial facilities (~29%) accounting for the majority of total emissions (ISA, section 2.1). Other anthropogenic sources of SO_2 include both the extraction of metal from ore as well as the burning of high sulfur containing fuels by locomotives, large ships, and non-road diesel equipment. Notably, almost the entire sulfur content of fuel is released as SO_2 or SO_3 during combustion. Thus, based on the sulfur content in fuel stocks, oxides of sulfur emissions can be calculated to a higher degree of accuracy than can emissions for other pollutants such as PM and NO_2 (ISA, section 2.1).

The largest natural sources of SO_2 are volcanoes and wildfires. Although SO_2 constitutes a relatively minor fraction (0.005% by volume) of total volcanic emissions, concentrations in volcanic plumes can be in the range of several to tens of ppm (thousands of ppb). Volcanic sources of SO_2 in the U.S. are limited to the Pacific Northwest, Alaska, and Hawaii. Emissions of SO_2 can also result from burning vegetation. The amount of SO_2 released from burning vegetation is generally in the range of 1 to 2% of the biomass burned and is the result of sulfur from amino acids being released as SO_2 during combustion.

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[1] U.S. Environmental Protection Agency (2007c), Review of the National Ambient Air Quality Standards for SO_2: Policy Assessment of Scientific and Technical Information, Integrated Science Assessment, Chapter 2, EPA-452/R-08-xxx, Office of Air Quality Planning and Standards, RTP, NC.

Emissions inventory inputs representing the year 2005 for the sources above were developed to provide a base year for the air quality analysis presented in Chapter 3. The 2005 National Emissions Inventory (NEI), version 2 from October 6, 2008 was the starting point for the U.S. inventories used for the air quality analysis. This inventory includes 2005-specific data for most point and mobile sources, while most nonpoint and other data were carried forward from version of the 2002 NEI. For more information on the 2005 NEI, upon which significant portions of the 2005 modeling platform are based, see http://www.epa.gov/ttn/chief/net/2005inventory.html.

2.2 Air Quality Monitoring Data

2.2.1 Background on SO_2 monitoring network

The following section provides general background on the SO_2 monitoring network. A more detailed description of this network can be found in Watkins (2009). The SO_2 monitoring network was originally deployed to support implementation of the SO_2 NAAQS established in 1971. Despite the establishment of an SO_2 standard, uniform minimum monitoring requirements for SO_2 monitoring did not appear until May 1979. From the time of the implementation of the 1979 monitoring rule through 2008, the SO_2 network has steadily decreased in size from approximately 1496 sites in 1980 to the approximately 488 sites operating in 2008.

The 1979 monitoring rule established two categories of SO_2 monitoring sites: State and Local Ambient Monitoring Stations (SLAMS) and the smaller set of National Ambient Monitoring Stations (NAMS). No minimum requirements were established for SLAMS. Minimum requirements (described below) were established for NAMS. The 1979 rule also required that SO_2 only be monitored using Federal Reference Methods (FRMs) or Federal Equivalent Methods (FEMs). The 1979 monitoring rule called for a range of number of sites in a metropolitan statistical area (MSA) based both on population size and known concentrations relative to the NAAQS (at that point in time; see Watkins, 2009).

In October 2006, EPA revised the monitoring requirements for SO_2 in light of the fact that there was not an SO_2 non-attainment problem (Watkins, 2009). The 2006 rule eliminated the minimum requirements for the number of SO_2 monitoring sites. The current SO_2 monitoring rule, 40 CFR Part 58, Appendix D, section 4.4 states:

Sulfur Dioxide (SO_2) Design Criteria:

(a) There are no minimum requirements for the number of SO_2 monitoring sites. Continued operation of existing SLAMS SO_2 sites using FRM or FEM is required until discontinuation is approved by the EPA Regional Administrator. Where SLAMS SO_2 monitoring is ongoing, at least one of the SLAMS SO_2 sites must be a maximum concentration site for that specific area.

(b) The appropriate spatial scales for SO_2 SLAMS monitoring are the microscale, middle, and possibly neighborhood scales. The multi-pollutant NCore sites can provide for metropolitan area trends analyses and general control strategy progress tracking. Other SLAMS sties are expected to provide data that are useful in specific compliance actions, for maintenance plan agreements, or for measuring near specific stationary sources of SO_2.

(1) Micro and middle scale – Some data uses associated with microscale and middle scale measurements for SO_2 include assessing the effects of control strategies to reduce concentrations (especially for the 3-hour and 24-hour averaging times) and monitoring air pollution episodes.

(2) Neighborhood scale – This scale applies where there is a need to collect air quality data as part of an ongoing SO_2 stationary source impact investigation. Typical locations might include suburban areas adjacent to SO_2 stationary sources for example, or for determining background concentrations as part of these studies of population responses to exposure to SO_2.

(c) Technical guidance in reference 1 of this appendix should be used to evaluate the adequacy of each existing SO_2 site, to relocate an existing site, or to locate new sites.

To ascertain what the current SO_2 network is addressing or characterizing, and in light of the relatively recent removal of a specific SO_2 monitoring requirement, EPA reviewed some of the SO_2 network meta-data (Watkins, 2009). The data reviewed are those available from AQS for calendar year 2008, for any monitors reporting data at any point during the year. In 2008, there were 488 SO_2 monitors reporting data to AQS at some point during the year.

2.2.2 Ambient concentrations of SO_2

Since the integrated exposure to a pollutant is the sum of the exposures over all time intervals for all environments in which the individual spends time, understanding the temporal and spatial patterns of SO_2 levels across the U.S is an important component of conducting air quality, exposure, and risk analyses. SO_2 emissions and ambient concentrations follow a strong east to west gradient due to the large numbers of coal-fired electric generating units in the Ohio River Valley and upper Southeast regions. In the 12 CMSAs that had at least 4 SO_2 regulatory monitors from 2003-2005, 24-hour average concentrations in the continental U.S. ranged from a reported low of ~1 ppb in Riverside, CA and San Francisco, CA to a high of ~12 ppb in Pittsburgh, PA and Steubenville, OH (ISA, section 2.4.4). In addition, inside CMSAs from 2003-2005, the annual average SO_2 concentration was 4 ppb (ISA, Table 2-8). However, spikes in hourly concentrations occurred; the mean 1-hour maximum concentration was 130 ppb, with a maximum value of greater than 700 ppb (ISA, Table 2-8).

In addition to considering 1-hour, 24-hour, and annual SO_2 levels, examining the temporal and spatial patterns of 5-minute peaks of SO_2 is also important given that human clinical studies have demonstrated exposure to these peaks can result in adverse respiratory effects in exercising asthmatics (see REA, Chapter 4). Although the total number of SO_2 monitors across the continuous U.S. can vary from year to year, in 2006 there were approximately 500 SO_2 monitors in the NAAQS monitoring network (ISA, section 2.5.2). State and local agencies responsible for these monitors are required to report 1-hour average SO_2 concentrations to the EPA Air Quality System (AQS). However, a small number of sites, only 98 total from 1997 to 2007, and not the same sites in all years, voluntarily reported 5-minute block average data to AQS (ISA, section 2.5.2). Of these, 16 reported all twelve 5-minute averages in each hour for at least part of the time between 1997 and 2007. The remainder reported only the maximum 5-minute average in each hour. When maximum 5-minute concentrations were reported, the absolute highest concentration over the ten-year period exceeded 4000 ppb, but for all individual monitors, the 99th percentile was below 200 ppb (ISA, section 2.5.2). Medians from these monitors reporting data ranged from 1 ppb to 8 ppb, and the average for each maximum 5-minute level ranged from 3 ppb to 17 ppb. Delaware, Pennsylvania, Louisiana, and West Virginia had mean values for maximum 5-minute data exceeding 10 ppb (ISA, section 2.5.2). Among aggregated within-state data for the 16 monitors from which all 5-minute average intervals were reported, the median values ranged from 1 ppb to 5 ppb, and the means ranged from 3 ppb to 11 ppb (ISA, section 2.5.2). The highest reported concentration was 921 ppb, but the 99th percentile values for aggregated within-state data were all below 90 ppb (ISA, section 2.5.2).

Chapter 3: Air Quality Analysis

Synopsis

This chapter describes the approach used to calculate 2020 baseline SO_2 design values and the amount of emissions reductions needed to attain the alternative 1-hour SO_2 NAAQS. The NAAQS being analyzed are 50, 75, and 100 ppb based on design values calculated using the 3-year average of the 99th percentile 1-hour daily maximum concentrations based on the monitoring network described in Chapter 2. The projected 2020 baseline SO_2 design values are used to identify 2020 nonattainment counties and to calculate, for each such county, the amount of reduction in SO_2 concentration necessary to attain the alternative NAAQS. This chapter also describes the approach for calculating "ppb SO_2 concentration per ton SO_2 emissions" ratios that are used to estimate the amount of SO_2 emissions reductions that may be needed to provide for attainment of the alternative SO_2 standards. As described below, the air quality analysis relies on SO_2 emissions from simulations of the Community Multiscale Air Quality (CMAQ) model coupled with ambient 2005-2007 design values and emissions data to project 2020 SO_2 design value concentrations and the "ppb per ton" ratios. A description of CMAQ is provided in the Ozone NAAQS RIA Air Quality Modeling Platform Document (EPA, 2008).

3.1 2005-2007 Design Values

The proposed standard is based on the 3-year average of the 99th percentile concentration of the daily 1-hour maximum concentration for a year. The design value for each percentile is calculated as:

- Identify daily 1-hour maximum concentration for each day for each year
- Calculate 99th percentile values of the daily 1-hour maximum concentrations for each year
- Average the 99th percentile values for the three years.

Monitors that had valid measurements for at least 75% of the day, 75% of the days in a quarter and all 4 quarters for all three years were included in the analysis[1]. The resulting 3-year averaged 99th percentile daily 1-hour maximum concentrations are shown in Figure 3.1 for 229 monitored counties. Counties in blue, green, and dark red would exceed the lowest alternative standard considered in the RIA, 50 ppb. Monitors with design values of 50.0 to 50.4 ppb would not exceed the standard 50 ppb as those concentrations would round to 50 ppb.

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[1] Email from Rhonda Thompson to James Thurman, January 22, 2009.

Concentrations 50.5 ppb and higher are considered exceeding the lowest alternative standard. Similar rounding is done for the 75, and 100 ppb alternative standards (75.4 and 100.4 are the cut-offs for nonattainment). A summary of the number of counties exceeding the alternative standards for 2005-2007 is shown in Table 3.1. Appendix 3 contains the complete list of 2005-2007 design values used in calculation of the 2020 design values. Table 3.2 lists the top ten counties for the 99th percentile design values for 2005-2007.

Figure 3.1. 2005-2007 3-year averaged design values (ppb) for 99th percentile daily 1-hour maximum SO$_2$ concentrations. Values shown are county maxima.

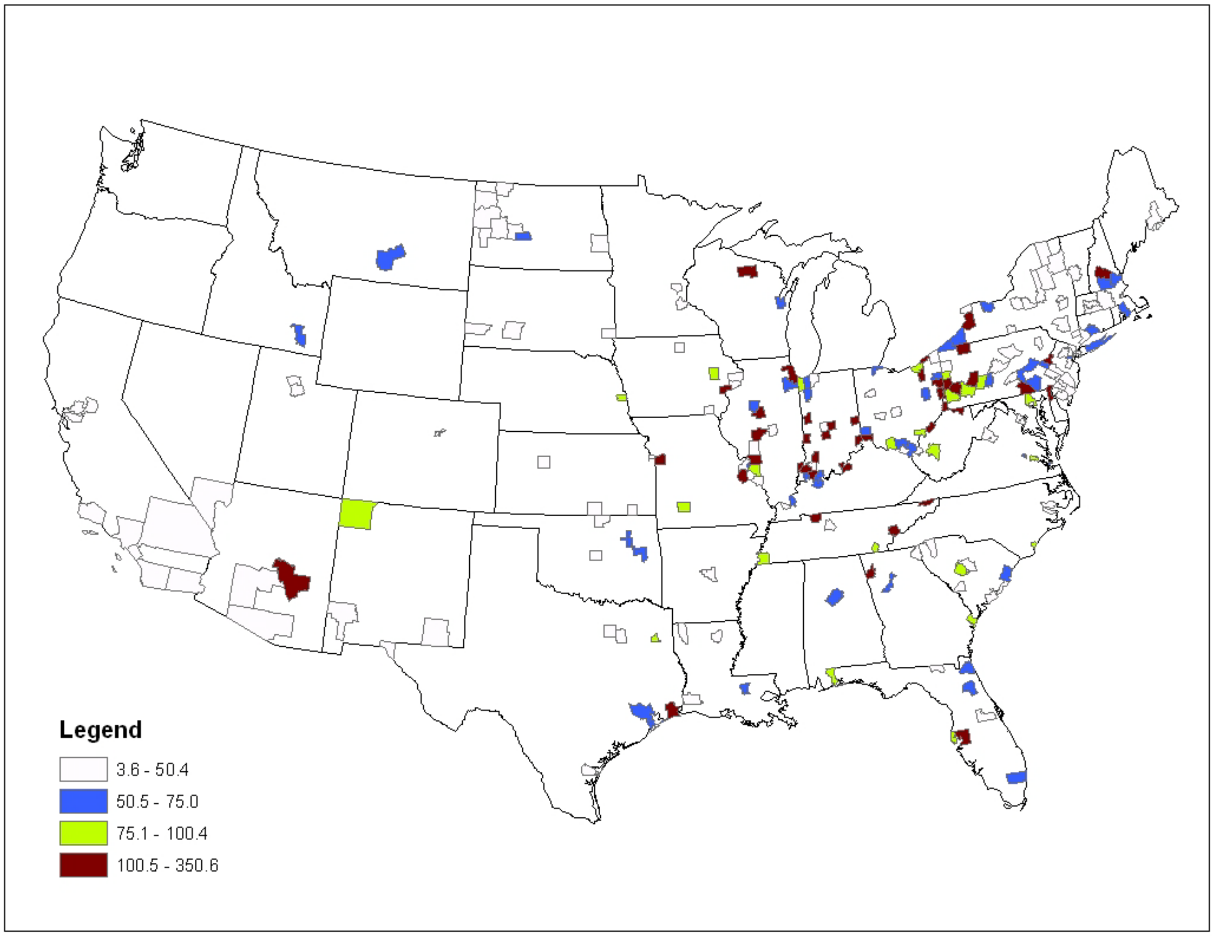


Table 3.1. Number of monitors and counties exceeding 50, 75, and 100 ppb alternative standards for the 99th percentile design values for 2005-07.

Alternative standard (ppb)	Number of monitors	Number of counties
50	169	119
75	95	70
100	59	46

Table 3.2. Top 10 2005-07 counties 99th percentile design values.

State	County	Design value (ppb)
MO	Jefferson	350.6
AZ	Gila	286.0
IL	Tazewell	222.3
PA	Warren	214.0
TN	Blount	196.3
PA	Northampton	187.0
IN	Fountain	183.0
OH	Lake	180.3
WI	Oneida	179.0
IN	Floyd	176.3

3.2 Calculation of 2020 Projected Design Values

The 2020 baseline design values were determined using CMAQ gridded emissions for 2005 and 2020. Gridded emissions were utilized instead of county emissions because of the influence of stationary sources on SO_2 concentrations. For monitors near county boundaries, stationary sources in a neighboring county may have more influence over the monitor than a stationary source in the monitor's home county. The SO_2 emissions in the CMAQ runs reflect reductions from the following controls and programs shown in Table 3.3.

Table 3.3. Controls in the 2020 SO_2 inventory.

Control Strategies	Approach or Reference:
Non-EGU Point Controls	
Consent decrees apportioned to several plants	
DOJ Settlements: plant SCC controls	1
Alcoa, TX	
Premcor (formerly MOTIVA), DE	
Refinery Consent Decrees: plant/SCC controls	2
Closures, pre-2007: plant control of 100%	3
Auto plants	
Pulp and Paper	
Large Municipal Waste Combustors	
Small Municipal Waste Combustors	
Plants closed in preparation for 2005 inventory	
Small Municipal Waste Combustors (SMWC)	4
Solid Waste Rules (Section 129d/111d)	EPA, 2005
Hospital/Medical/Infectious Waste Incinerator Regulations	
MACT rules, plant-level, PM & SO_2: Lime Manufacturing	5
Stationary Area Assumptions	
Residential Wood Combustion Growth and Changeouts to year 2020	6
EGU Point Controls	
Clean Air Interstate Rule	7; EPA, 2005
Onroad Mobile and Nonroad Mobile Controls (list includes all key mobile control strategies but is not exhaustive)	
Tier 2 Rule	EPA, 1999
2007 Onroad Heavy-Duty Rule	EPA, 2000
Final Mobile Source Air Toxics Rule (MSAT2)	EPA, 2007
Renewable Fuel Standard	EPA, 2010
Clean Air Nonroad Diesel Final Rule – Tier 4	8, EPA, 2004
Control of Emissions from Nonroad Large-Spark Ignition Engines and Recreational Engines (Marine and Land Based): "Pentathalon Rule"	8,9,10
Clean Bus USA Program	
Control of Emissions of Air Pollution from Locomotives and Marine Compression-Ignition Engines Less than 30 Liters per Cylinder	
Aircraft, Locomotives, and Commercial Marine Assumptions	
Aircraft:	11
Itinerant (ITN) operations at airports to year 2020	
Locomotives:	EPA, 2009; 12; 9
Energy Information Administration (EIA) fuel consumption projections for freight rail	
Clean Air Nonroad Diesel Final Rule – Tier 4	
Locomotive Emissions Final Rulemaking, December 17, 1997	
Control of Emissions of Air Pollution from Locomotives and Marine	

Control Strategies	Approach or Reference:
Commercial Marine: EIA fuel consumption projections for diesel-fueled vessels OTAQ ECA C3 Base 2020 inventory for residual-fueled vessels Clean Air Nonroad Diesel Final Rule – Tier 4 Emissions Standards for Commercial Marine Diesel Engines, December 29, 1999 Tier 1 Marine Diesel Engines, February 28, 2003	12; EPA, 2009

1. For ALCOA consent decree, used http:// cfpub.epa.gov/compliance/cases/index.cfm; for MOTIVA: used information sent by State of Delaware
2. Used data provided by Brenda Shine, EPA, OAQPS
3. Closures obtained from EPA sector leads; most verified using the world wide web.
4. Used data provided by Walt Stevenson, EPA, OAQPS
5. Percent reductions recommended are determined from the existing plant estimated baselines and estimated reductions as shown in the Federal Register Notice for the rule. SO_2 % reduction will therefore be 6147/30,783 = 20% and PM10 and PM2.5 reductions will both be 3786/13588 = 28%
6. Expected benefits of woodstoves change-out program: http://www.epa.gov/woodstoves/index.html
7. http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/summary2006.pdf
8. http://www.epa.gov/nonroad-diesel/2004fr.htm
9. http://www.epa.gov/cleanschoolbus/
10. http://www.epa.gov/otaq/marinesi.htm
11. Federal Aviation Administration (FAA) Terminal Area Forecast (TAF) System, December 2007: http://www.apo.data.faa.gov/main/taf.asp
12. http://www.epa.gov/nonroad-diesel/2004fr.htm

In brief, these CMAQ emissions were at 12 km horizontal resolution for two modeling domains which, collectively, cover the lower 48 States and adjacent portions of Canada and Mexico. The boundaries of these two domains are shown in Figure 3.2. The spatial distribution of the emissions for 2005 and 2020 can be seen in Figures 3.3 and 3.4 respectively. In both figures, the lines radiating from the coast are the commercial marine vessel emissions. Figure 3.5 shows the reduction in emissions between 2005 (16.3 million tons) and 2020 (9.6 million tons) by source sector (EGU, non-EGU point, commercial marine vessel, and other sources) with the decrease from 2005 to 2020 due mostly to decreases in EGU emissions.

3.2.1 2020 Design Value Calculation Methodology

Ambient monitored data were assigned to CMAQ grid cells using ArcGIS. Since there were areas of the country where the eastern and western domains overlapped, monitors in these overlapping areas were assigned to the eastern or western grid cells by using a "combined grid." This combined grid was a mesh of the eastern and western domains, with overlapping areas assigned eastern grid cells or western grid cells based on the location relative to the dividing line shown in Figure 3.2. Figure 3.2 shows the assignment of monitors to the two domains. An example of monitors in both domains was the El Paso County monitors. These monitors were assigned to the western domain. The gridded 2006 and 2020 emissions were also assigned to the combined grid based on the same grid assignments as the monitors.

Figure 3.2. Monitor domain assignments. Western domain is outlined in blue and eastern domain outlined in red. Black vertical line denotes dividing line between eastern and western domains for monitor assignments. Monitors in blue were assigned to the western domain and monitors in red were assigned to the eastern domain.

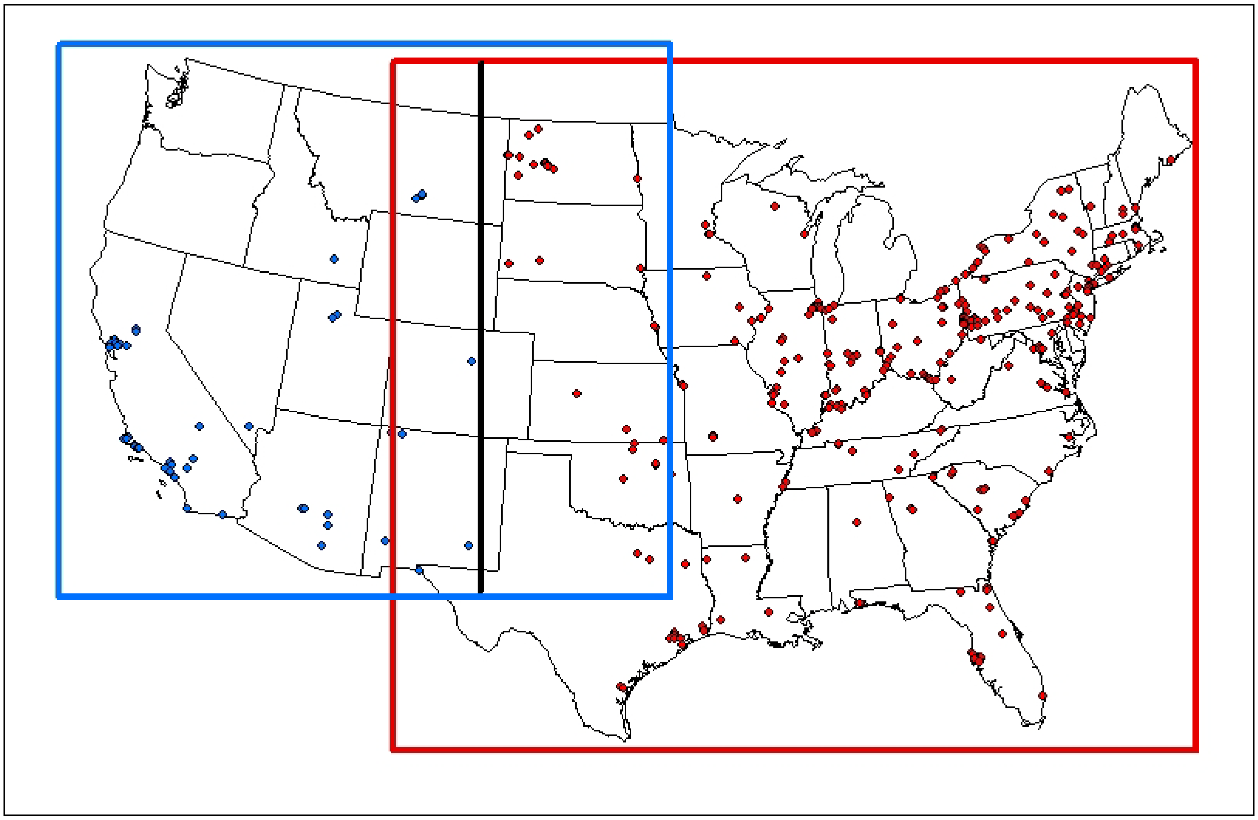


Figure 3.3. 2005 annual 12 km gridded SO_2 emissions (tons).

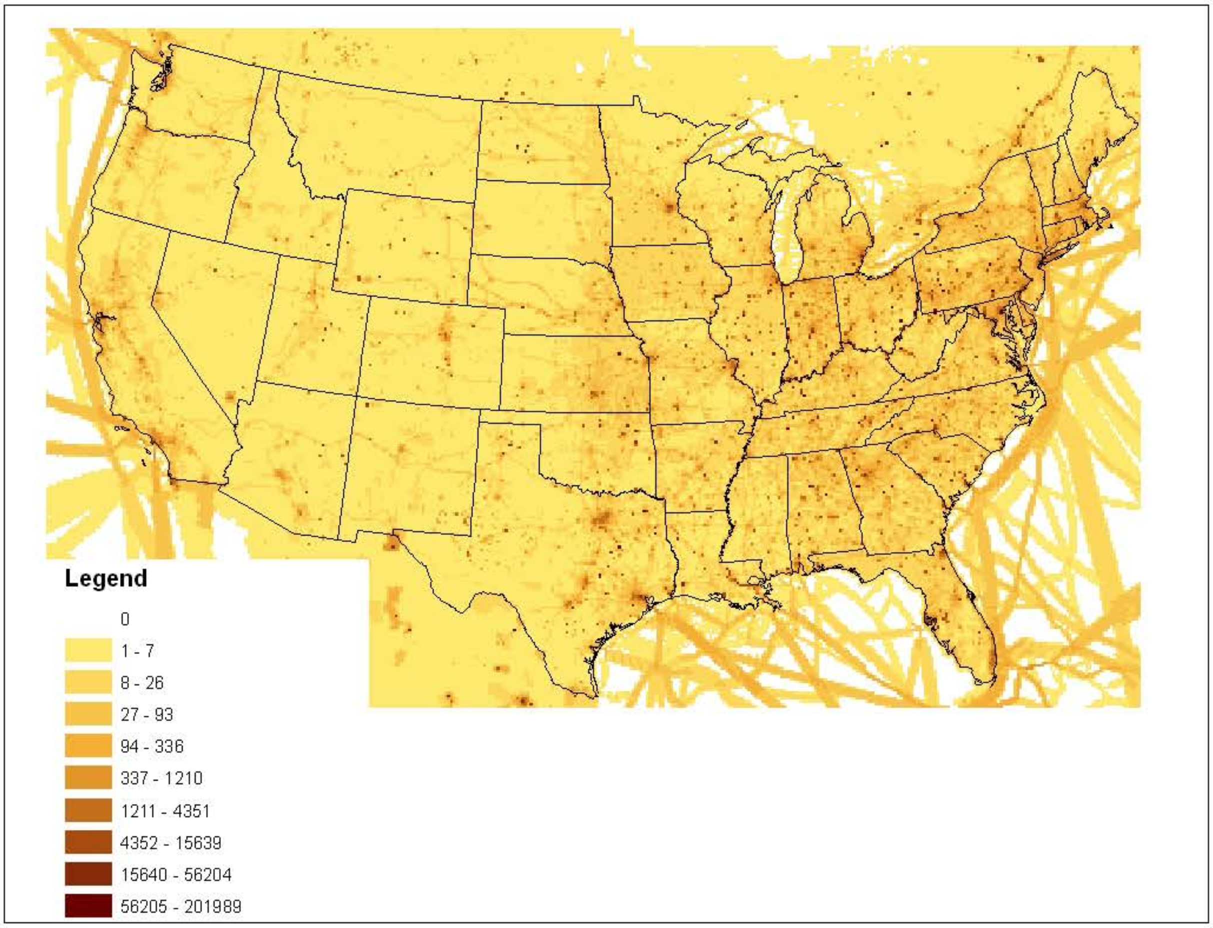


Figure 3.4. 2020 annual 12 km gridded SO_2 emissions (tons).

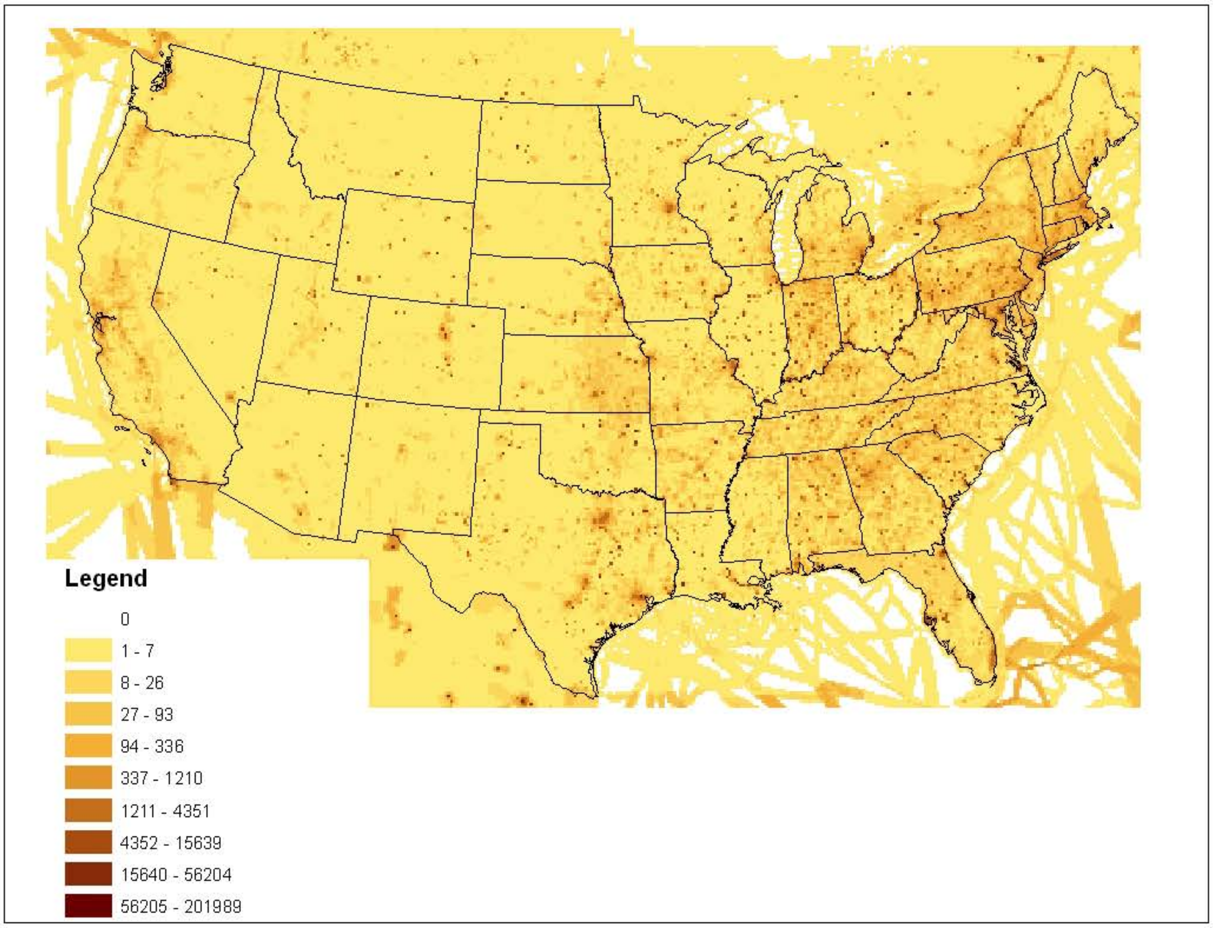
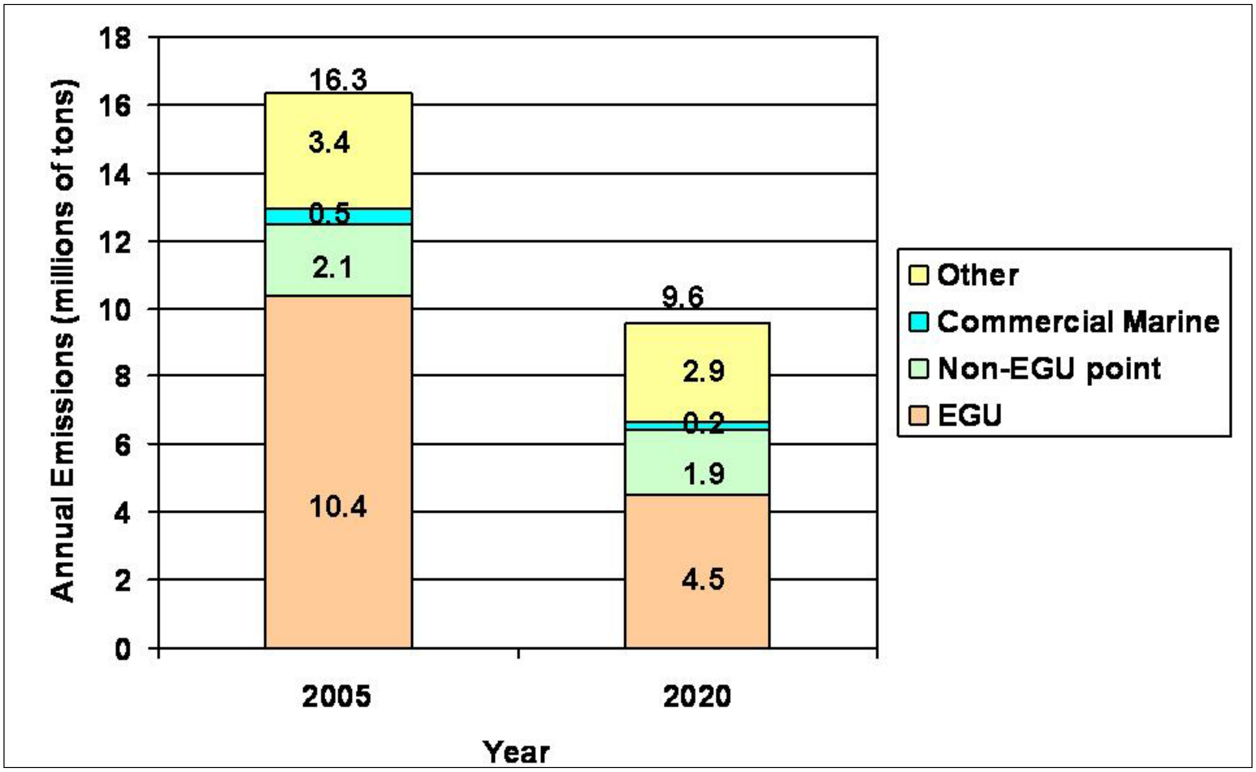
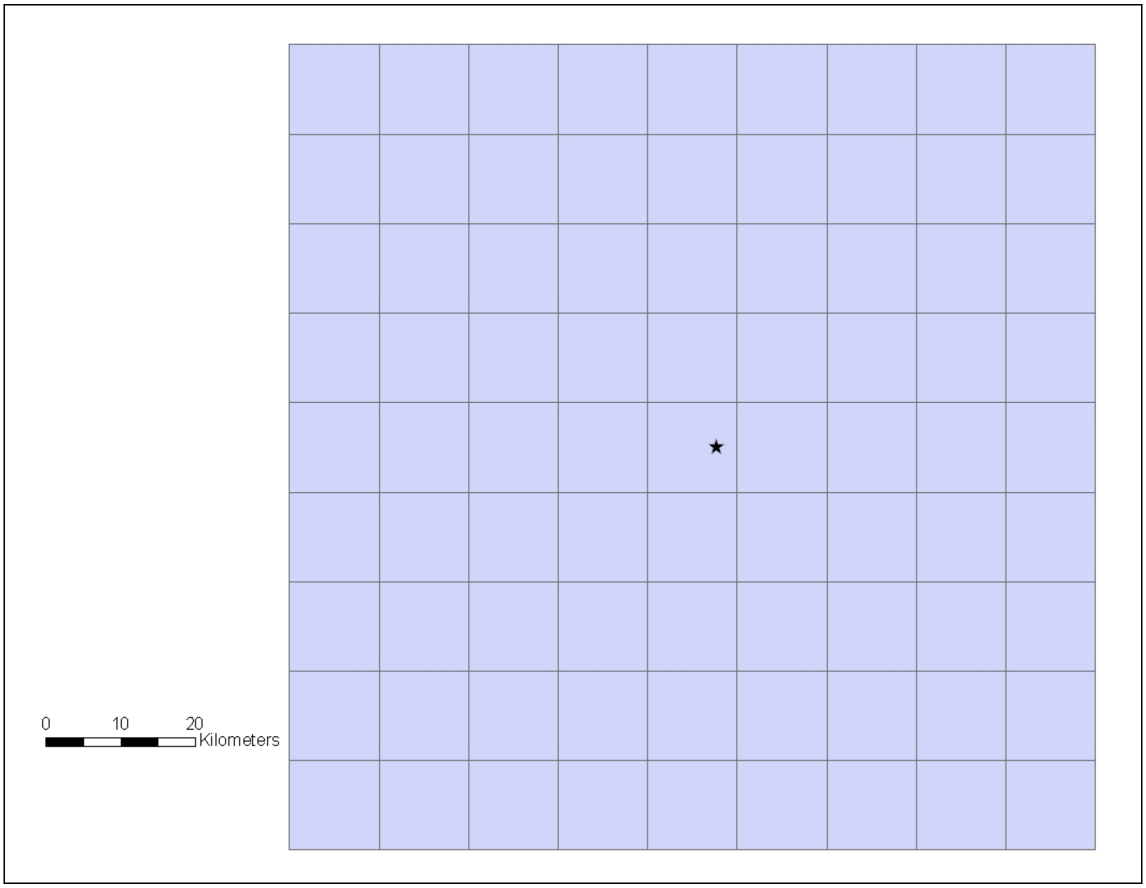


Figure 3.5. 2005 and 2020 SO_2 emissions (tons) by source sector.



Once the monitors and emissions were assigned to the combined grid, for each monitor, a 9x9 matrix of grid cells was selected, centered on the monitor's grid cell. An example is shown in Figure 3.6. The 9x9 matrix represented an approximate domain of emissions extending out 50 km from the monitor, the upper range of near-field dispersion. Since the design values were based on hourly concentrations, extending the radius of influential emissions on the monitor grid cell to 50 km was considered appropriate.

Figure 3.6. 9 x 9 matrix of 12km grid cells centered on CMAQ cell containing an SO_2 monitor (star).



Once the matrices of grid cells were created for each monitor, the 2005 and 2020 gridded emissions were summed for each year across the 81 grid cells to result in total 2005 and 2020 emissions for each monitor. The summed 2020 emissions were then divided by the 2005 emissions to get an emissions change ratio:

$$E_{ratio} = \frac{E_{2020}}{E_{2005}} \tag{3.1}$$

Where E_{2020} are the summed 81 grid cell emissions for 2020, E_{2005} are the summed 81 grid cell emissions for 2005 and E_{ratio} is the ratio of 2020 emissions to 2005 emissions.

The 2005-2007 99th percentile design value concentrations were then multiplied by the emissions ratio to calculate the 2020 design values.

$$DV_{2020"99} = DV_{2005-2007:99} \times E_{ratio} \tag{3.2}$$

Where E_{ratio} is as defined above, $DV_{2005\text{-}2007:99}$ is the 2005-2007 3-year averaged design value for the 99th percentile, and $DV_{2020:99}$ is the projected 2020 design value for the 99th percentile.

After calculating the 2020 design values, a ppb/ton estimate was calculated by:

$$ppb/ton_{99} = \left(DV_{20205:99} - DV_{2005-2007:99}\right) \Big/ \left(E_{2020} - E_{2005}\right) \tag{3.3}$$

Where E_{2020} and E_{2005} are the summed emissions as defined for Equation 3.1, $DV_{2005\text{-}2007:99}$ and $DV_{2020:99}$ are as defined above and ppb/ton_{99} is the ppb/ton estimate for the 99th percentile.

Residual nonattainment estimates for the three alternative standards of 50, 75, and 100 ppb were calculated by subtracting the alternative standard from the 2020 design value. The absolute values of the alternative standards (50, 75, or 100 ppb) were not subtracted but rather the highest value that would meet the standards (50.4, 75.4, and 100.4 ppb) if design values were rounded to the nearest whole ppb. Once residual nonattainment was calculated for each alternative standard, for monitors exceeding the standards, tons needed for control were calculated by dividing residual nonattainment by the ppb/ton estimate:

$$Tons_{99:AS} = \frac{NA_{99:AS}}{ppb/ton_{99}} \tag{3.4}$$

Where ppb/ton_{99} is as defined above, $NA_{99:AS}$ is the residual nonattainment for alternative standard AS (50, 75, or 100 ppb) for the 99th percentile, and $Tons_{99:AS}$ are the tons needed to reach attainment for alternative standard AS for the 99th percentile.

3.2.2 Methodology Limitations

While the approach described in Section 3.2.1 is reasonable for a national analysis, there are limitations to the approach that may be better addressed by other methods such as near-field dispersion modeling on a case by case basis or fine scale CMAQ modeling. Given the number of monitors in the analysis, dispersion modeling for all monitors would not be feasible. Also, given that the CMAQ concentrations associated with the emissions used in this analysis are at 12 km horizontal resolution and that SO_2 is affected by nearby stationary sources, the CMAQ results may not be reasonable for this analysis, due to allocation of individual emission points within the grid cell. Limitations of this analysis include:

- Distance from source to monitor is not factored in the emissions sums used in Equation 3.1. All emission sources, regardless of distance and tonnage, are weighted equally.

Using Figure 3.6 as an example, a source may be located in the most northwestern grid cell and a source may be located in the same grid cell that contains the monitor. No distance weighting is applied to either source, based on its proximity to the monitor. They are both added to the emissions sum as is. Some monitors' emission sums may include large emission sources that are farther away from the monitor than smaller emission sources but the large emissions sources dominate the emissions used to calculate the ratio in Equation 3.1. These large sources, may have large changes in emissions from 2005 to 2020 and these changes could drastically affect the emissions ratio. Given the nature of the projection approach described in Section 3.2.1, these large emission changes may overestimate or underestimate the concentration change at the monitor given the distance from the source to the monitor and the factors mentioned in the points below, meteorology and terrain.

- Meteorology and terrain influences are not factored into the analysis. A source may not have a significant impact on a monitor because the prevailing wind direction is not from the source to the monitor, or the terrain between the source and monitor is configured such that the source does not have a significant impact on the monitor. This would also depend on building downwash effects and stack parameters such as stack height, exit temperature, stack diameter, and exit velocity.

3.3 Results

3.3.1. Nonattainment results

Table 3.4 lists the number of monitors and counties exceeding the three alternative standards for the 99th percentile 2020 design values. The number of counties exceeding each of the alternative standards decreased from 2005-2007 to 2020. Figure 3.7 shows the maximum 2020 design value for monitored counties for the 99th percentile design values. Counties in blue, green, and scarlet exceed the 50 ppb alternative standard. Table 3.5 lists the top 10 counties in 2020 for the 99th percentile design value along with residual nonattainment and tons needed for control to meet attainment. A complete list of 2020 design values for all monitors can be found in Appendix 3.

Table 3.4. Number of monitors and counties exceeding 50, 75, and 100 ppb alternative standards for the 99th percentile design values for 2020.

Alternative standard (ppb)	Number of monitors	Number of counties
50	71	56
75	27	24
100	11	9

Figure 3.7. 2020 design values (ppb) for 99th percentile daily 1-hour maximum SO_2 concentrations. Values shown are county maxima.

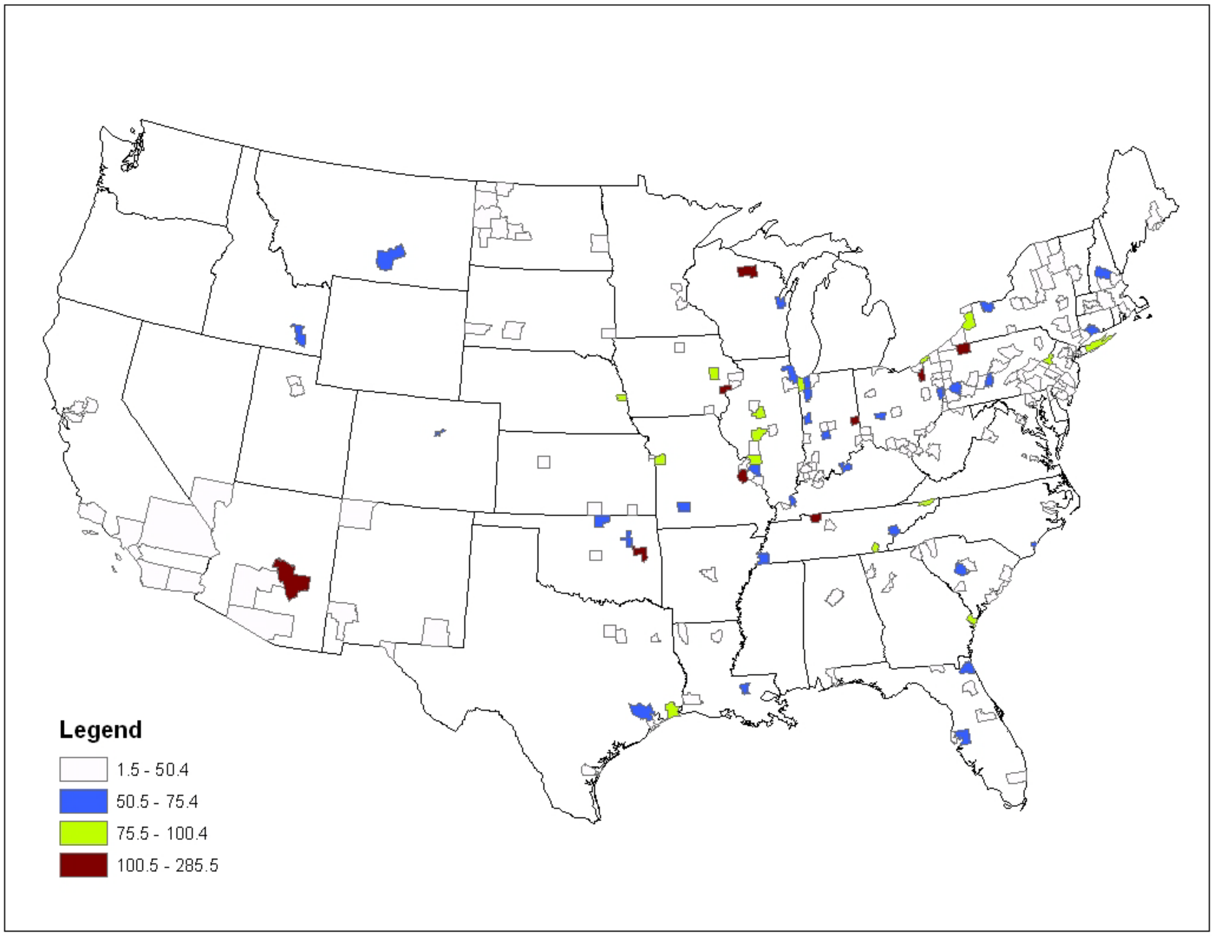


Table 3.5. Top 10 2020 counties 99th percentile design values (ppb).

			Alternative standards (ppb)					
			50		75		100	
State	County	2020 DV	Residual nonattainment	Tons for control	Residual nonattainment	Tons for control	Residual nonattainment	Tons for control
MO	Jefferson	285.5	235.1	139,033	210.1	124,249	185.1	109,464
AZ	Gila	284.8	234.4	21,930	209.4	19,591	184.4	17,252
PA	Warren	217.2	166.8	10,379	141.8	8,824	116.8	7,268
WI	Oneida	175.3	124.9	6,866	99.9	5,491	74.9	4,117
TN	Montgomery	144.3	93.9	19,764	68.9	14,502	43.9	9,240
IN	Wayne	134.3	83.9	24,088	58.9	16,911	33.9	9,733
IA	Muscatine	126.2	75.8	27,365	50.8	18,340	25.8	9,314
OK	Muskogee	104.9	54.5	45,542	29.5	24,651	4.5	3,760
OH	Summit	103.9	53.5	26,690	28.5	14,218	3.5	1,746
PA	Northampton	100.4	50.0	20,652	25.0	10.326	-	-

3.3.2 Example monitors

This section describes the emissions changes for two monitors' 99th percentile design values shown in Figures 3.8 and 3.9. One monitor's design value, Tazewell County, IL decreased from 2005-2007 to 2020 (Figure 3.8) and the other monitor's (Montgomery County, TN) design value increased from 2005-2007 to 2020 (Figure 3.9). Emissions summaries in the 81 cell matrices for both monitors are shown in Figure 3.10.

Figure 3.8. Location of monitor in Tazewell County, IL.

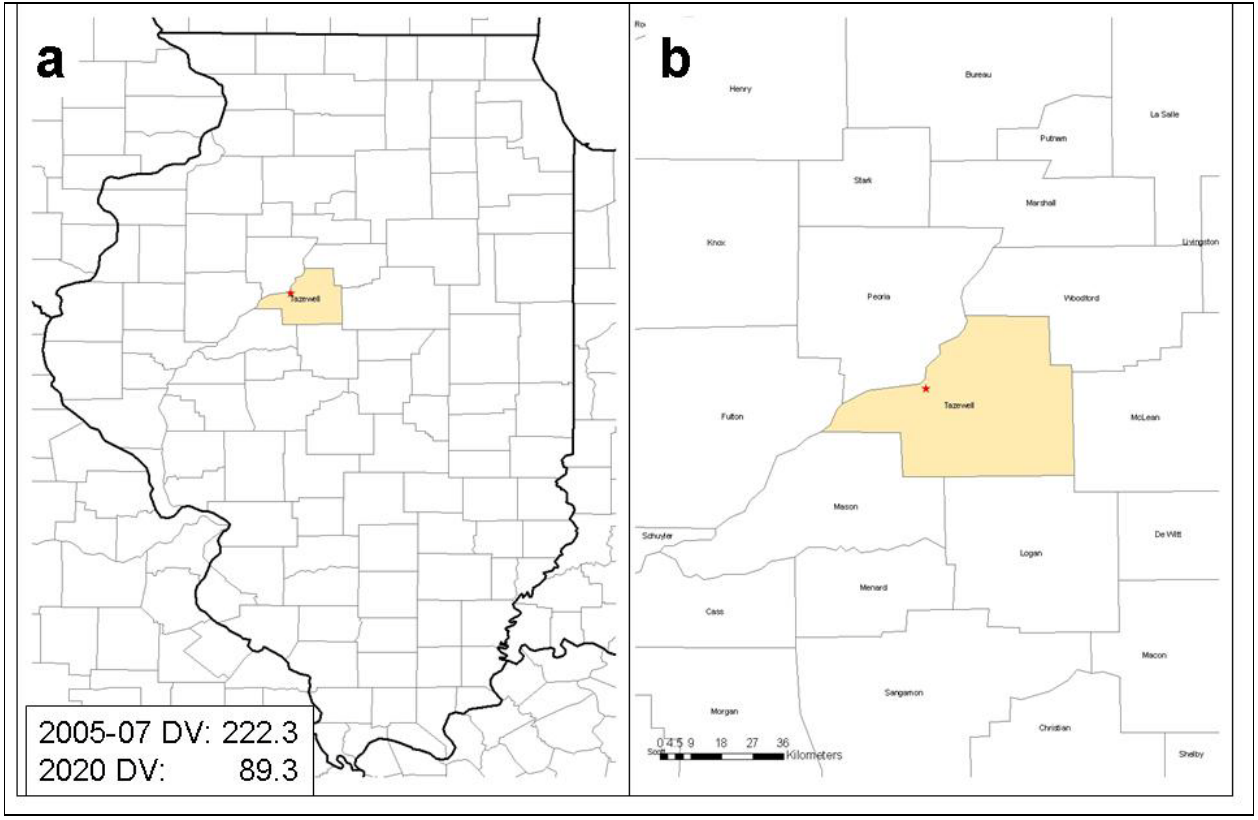


Figure 3.9. Location of monitor in Montgomery County, TN.

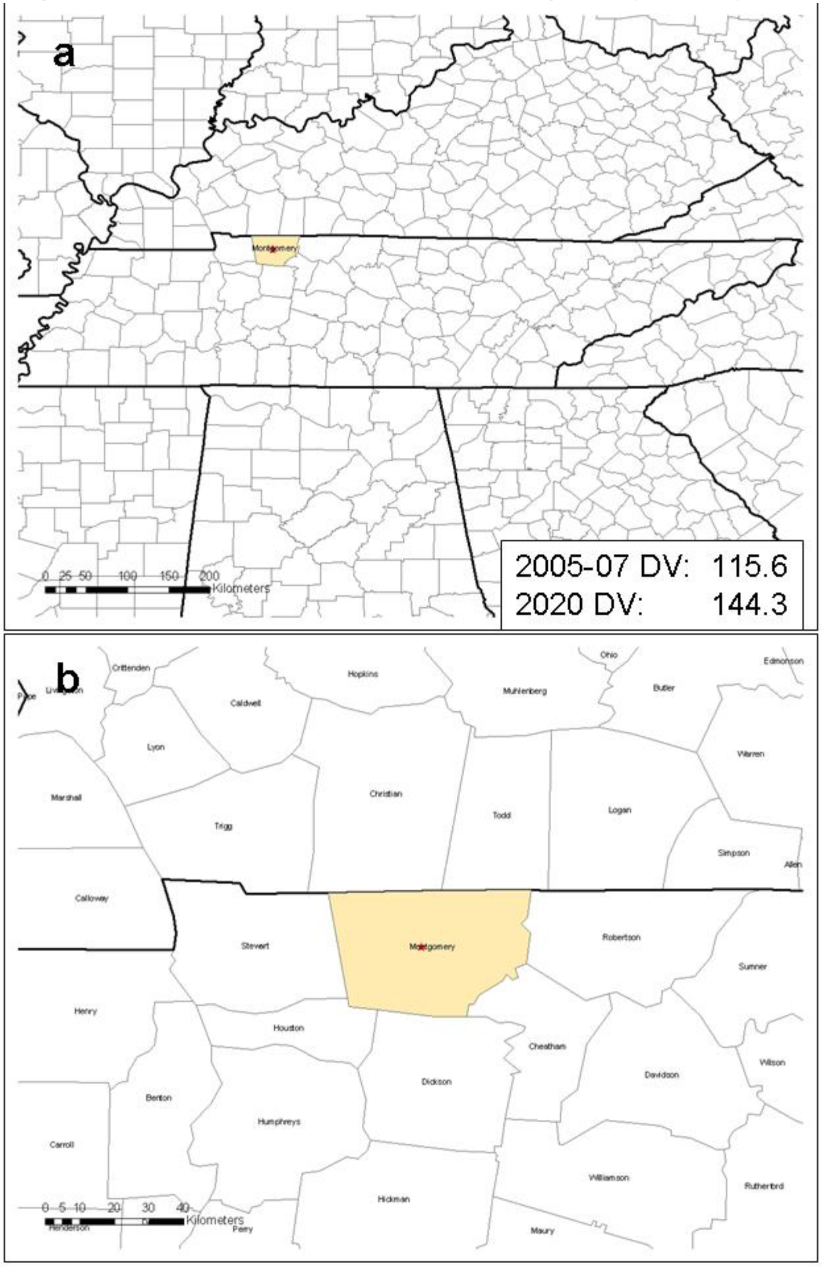
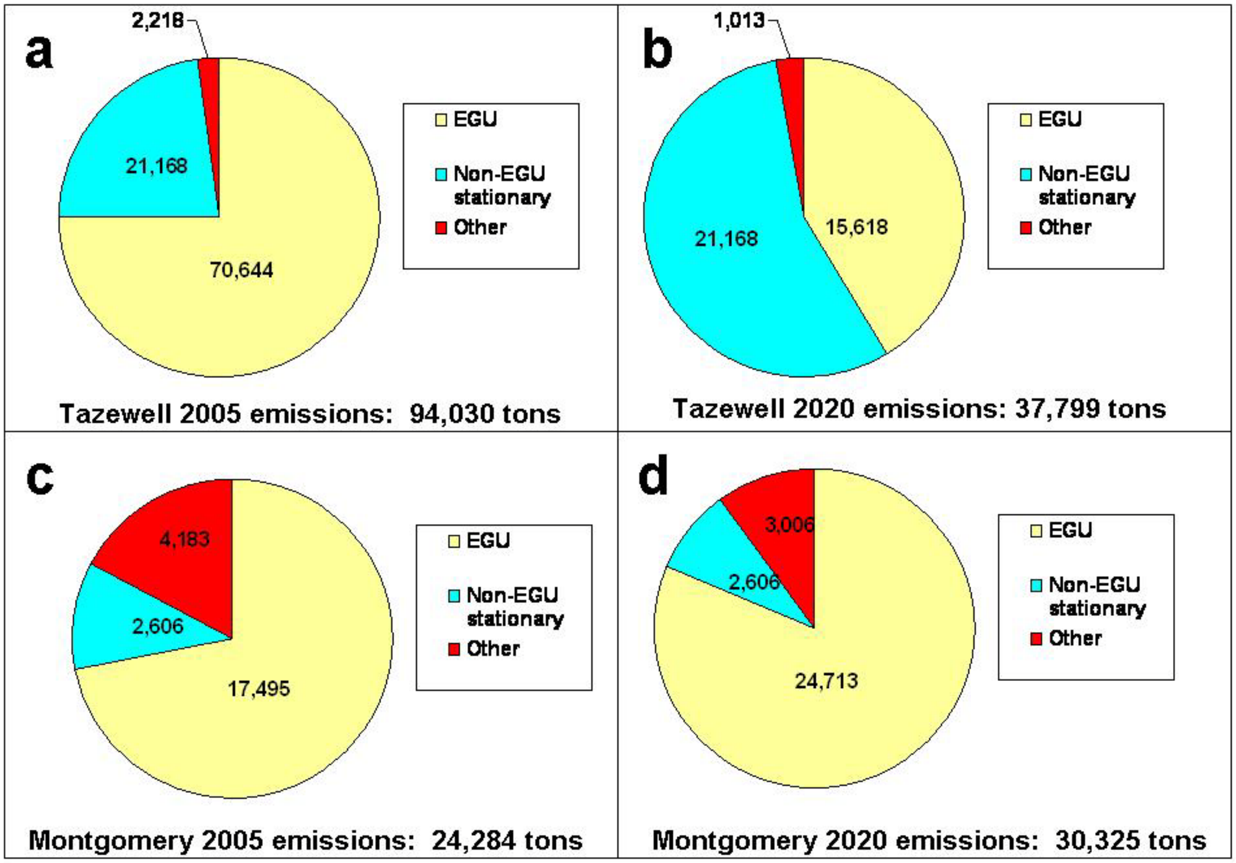


Figure 3.10. Tazewell County, IL and Montgomery County, TN monitors emissions (tons) for 2005 and 2020.



3.3.2.1 Tazewell County

Emissions affecting the Tazewell County monitor decreased from approximately 94,000 tons in 2005 to approximately 38,000 tons in 2020 (Figure 3.10 a and b). The decrease was mostly due to decreases in EGU emissions. The decrease caused the EGU sector drop from about 75% of the emissions to around 40% of the emissions. Figure 3.11 shows the spatial distribution of 2005 total emissions (all sources) within 50 km of the monitor and Figure 3.12 shows the spatial distribution of 2020 total emissions within 50 km of the monitor. The decrease in emissions can be seen as the emissions become more uniform outside of the "hotspot" grid cells.

Figure 3.11. 2005 12 km grid cell SO_2 total emissions (tons) for Tazewell County monitor. The red star represents the monitor location.

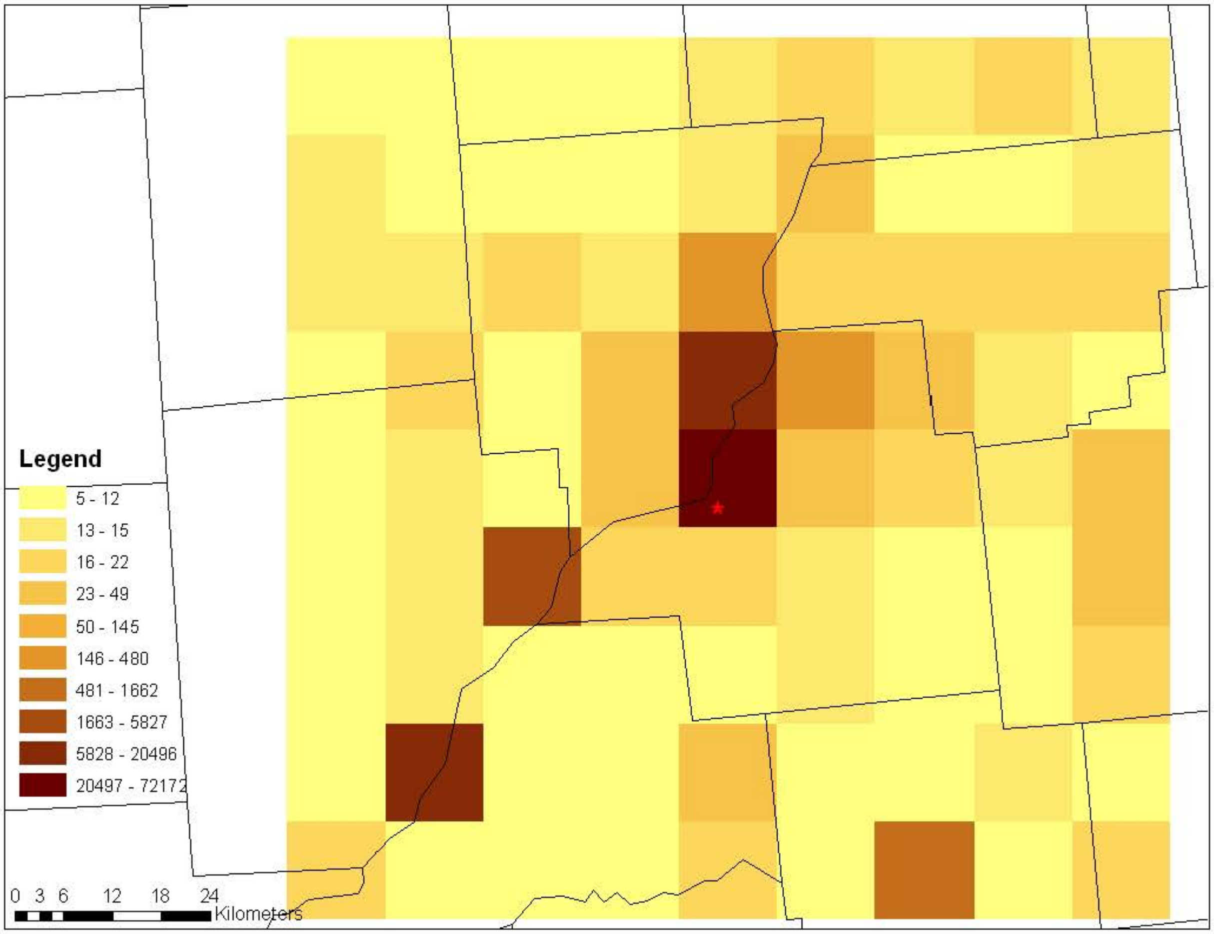
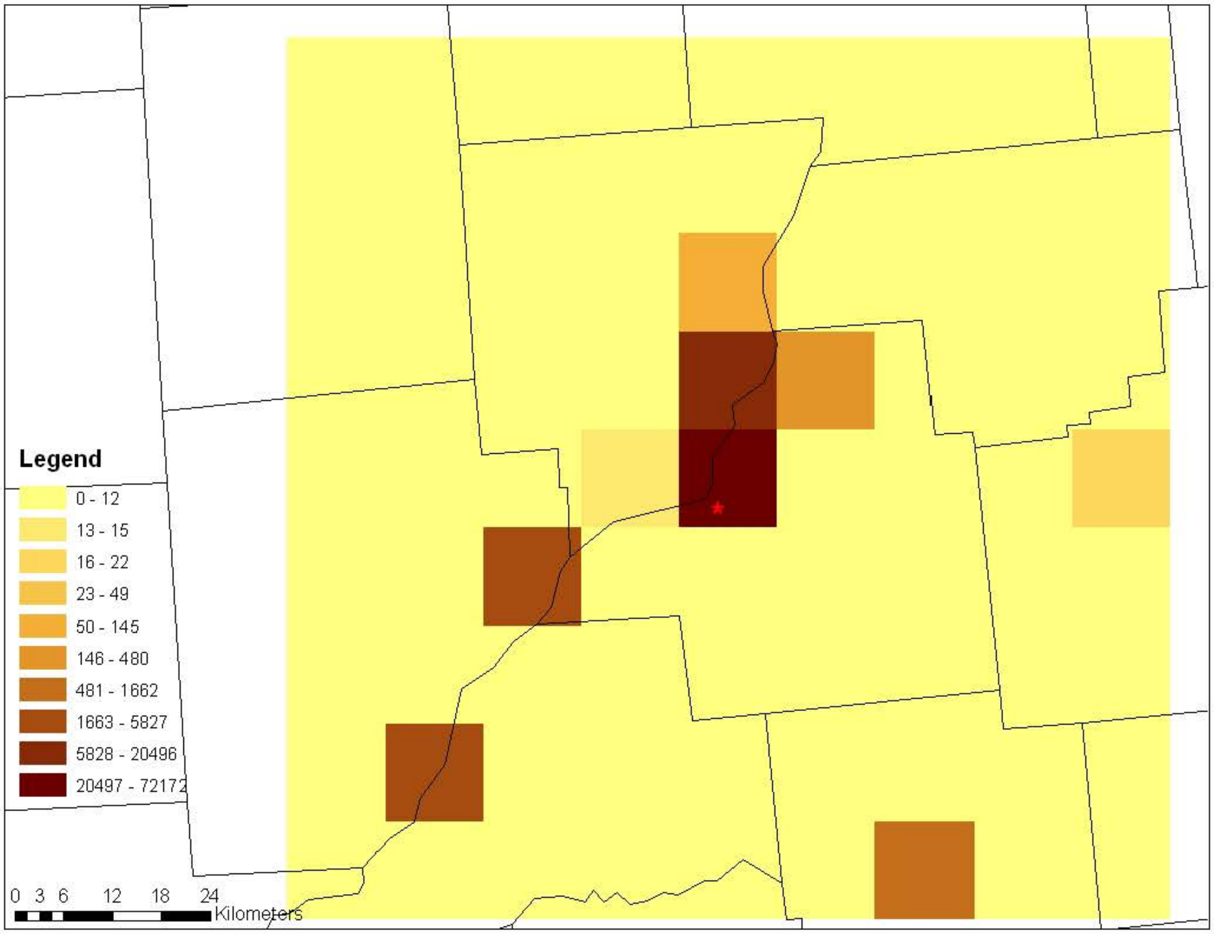


Figure 3.12. 2020 12 km grid cell SO_2 total emissions (tons) for Tazewell County monitor. The red star represents the monitor location.



3.3.2.2 Montgomery County

The design value for Montgomery County increased from 2005-07 to 2020 due to an increase in EGU emissions (Figure 3.10 c and d). Figures analogous to Figure 3.11 and Figure 3.12 are shown in Figure 3.13 and Figure 3.14. While emissions decrease outside the “hotspot” grid cells, the emissions within those hotspots increase from 2005 to 2020, as these are the locations of EGU facilities and the emissions increase from 2005 to 2020.

Figure 3.13. 2005 12 km grid cell SO_2 total emissions (tons) for Montgomery County monitor. The red star represents the monitor location.

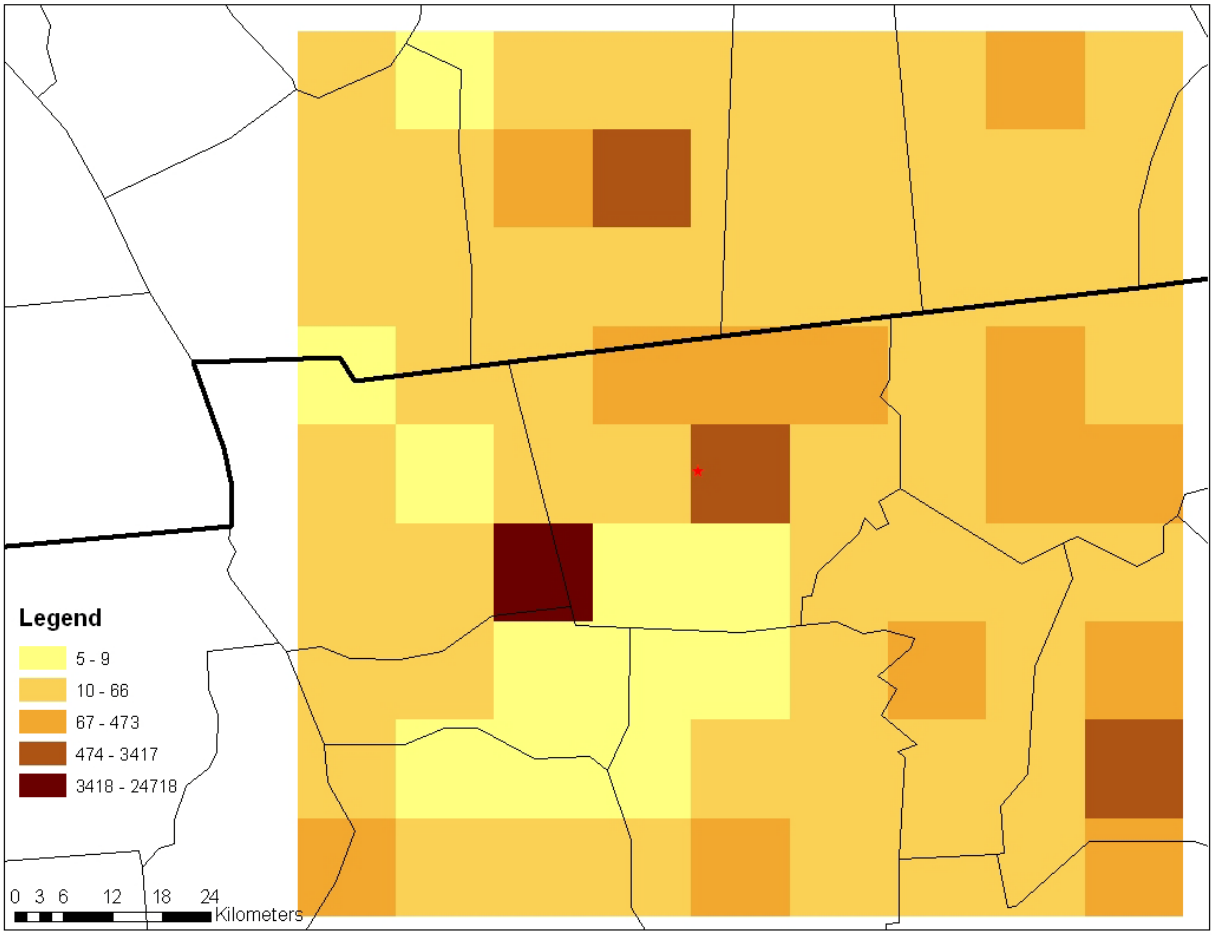
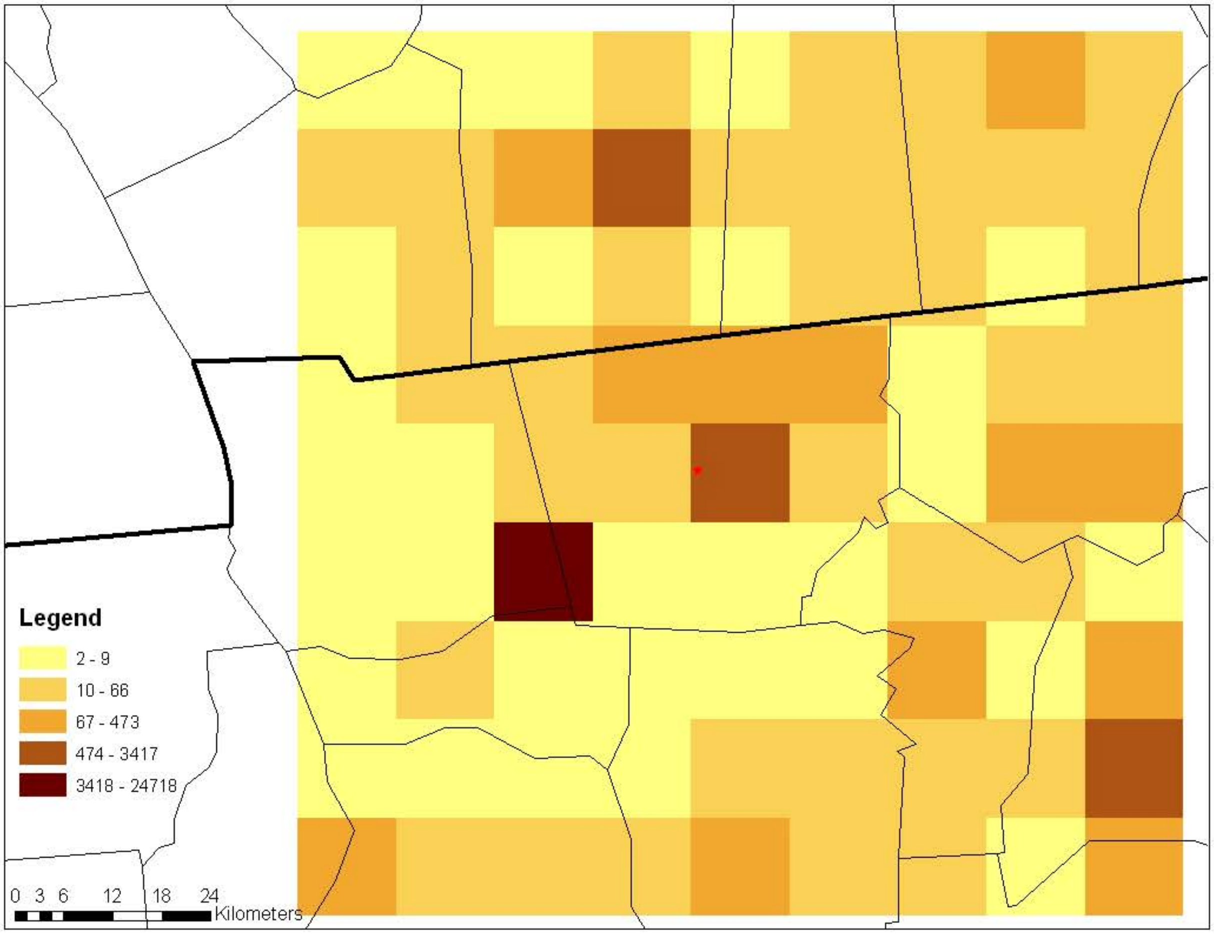


Figure 3.14. 2020 12 km grid cell SO_2 total emissions (tons) for Montgomery County monitor. The red star represents the monitor location.



3.4 Summary

In summary, 2020 baseline NO_2 design value concentrations were projected from 2005-2007 observed design values using CMAQ emissions output from 2005 and 2020. Results of the projections showed that, in 2020, nonattainment occurred for all three alternative standards (50, 75, and 100 ppb). However, the number of counties exceeding the standards dropped from the 2005-2007 period.

3.5 References

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Appendix 3a: 2005-2007 and 2020 Design Values

Table 3a-1 lists the 2005-2007 design values used in projecting 2020 design values for all monitors meeting the completeness criteria described in Section 3.1 of Chapter 3. Design values in black are below the 50 ppb alternative standard. Design values in blue exceed the 50 ppb alternative standard but are below 75 ppb. Design values in green exceed the 75 ppb alternative standard but are below 100 ppb. Values in red exceed 100 ppb. Exceedances of the alternative standards are based on the criteria discussed in Section 3.1 of Chapter 3.

Table 3a-1. SO_2 2005-2007 and 2020 projected 99th percentile design values (ppb).

State	County	Monitor	2005-07	2020
AL	Jefferson	1003	63.3	19.3
AZ	Gila	9	131.6	131.2
AZ	Gila	1001	286.0	284.8
AZ	Maricopa	3002	14.0	4.1
AZ	Maricopa	3003	9.3	2.8
AZ	Pima	1011	14.0	16.5
AR	Pulaski	7	10.0	12.5
CA	Contra Costa	2	18.6	12.5
CA	Contra Costa	6	18.0	11.6
CA	Contra Costa	1002	12.3	8.1
CA	Contra Costa	1004	14.6	9.4
CA	Contra Costa	2001	22.6	14.8
CA	Contra Costa	3001	25.6	17.2
CA	Imperial	5	20.9	20.4
CA	Los Angeles	1002	6.6	4.0
CA	Los Angeles	1103	10.6	6.3
CA	Los Angeles	4002	27.6	15.6
CA	Los Angeles	5005	19.6	11.6
CA	Orange	1003	9.3	5.4
CA	Sacramento	2	5.0	4.5
CA	Sacramento	6	5.6	5.1
CA	San Bernardino	306	10.0	8.2
CA	San Bernardino	1234	11.3	19.6
CA	San Bernardino	2002	8.0	7.2
CA	San Diego	1	9.6	8.6
CA	San Francisco	5	15.3	9.9
CA	Santa Barbara	8	4.0	0.6
CA	Santa Barbara	1013	4.6	2.0
CA	Santa Barbara	1020	44.3	6.7
CA	Santa Barbara	1025	8.0	1.3
CA	Santa Barbara	2004	5.6	1.6
CA	Santa Barbara	2011	3.3	0.5

State	County	Monitor	2005-07	2020
CA	Santa Barbara	4003	2.6	1.3
CA	Solano	4	10.0	6.5
CO	Denver	2	32.6	66.8
CT	Fairfield	12	35.6	46.4
CT	Fairfield	1123	25.3	24.2
CT	Fairfield	9003	27.6	29.4
CT	New Haven	27	60.6	60.9
CT	New Haven	2123	27.8	22.8
DE	New Castle	1008	125.0	48.7
DE	New Castle	2004	49.6	23.0
FL	Broward	10	64.6	35.4
FL	Duval	80	21.3	17.6
FL	Duval	81	69.0	57.0
FL	Duval	97	42.0	34.5
FL	Escambia	4	76.3	26.7
FL	Hamilton	15	31.6	24.5
FL	Hillsborough	81	47.3	20.6
FL	Hillsborough	95	42.6	19.1
FL	Hillsborough	109	119.0	53.5
FL	Hillsborough	1035	71.3	32.1
FL	Orange	2002	11.3	4.7
FL	Pinellas	23	96.3	36.4
FL	Pinellas	3002	42.0	15.8
FL	Pinellas	5002	77.6	27.8
FL	Pinellas	5003	83.3	43.2
FL	Putnam	1008	51.6	11.7
GA	Chatham	21	62.3	57.5
GA	Chatham	1002	94.6	87.4
GA	Floyd	3	110.0	10.2
GA	Fulton	48	73.0	10.2
GA	Fulton	55	60.0	22.7
ID	Bannock	4	69.6	61.7
IL	Cook	50	37.0	27.7
IL	Cook	63	40.6	29.2
IL	Cook	76	45.6	33.3
IL	Cook	1601	104.0	63.7
IL	Cook	4002	68.3	48.9
IL	Macon	13	47.0	48.6
IL	Macoupin	2	27.0	13.8
IL	Madison	1010	83.6	52.6
IL	Madison	3007	59.0	37.1
IL	Madison	3009	142.0	89.4
IL	Peoria	24	73.6	31.1
IL	Randolph	1	29.6	20.9
IL	St. Clair	10	91.3	59.4
IL	Sangamon	6	110.6	99.3
IL	Tazewell	4	222.3	89.3
IL	Wabash	1	152.3	40.5
IL	Wabash	1001	125.3	33.3

State	County	Monitor	2005-07	2020
IL	Will	13	64.6	32.0
IN	Daviess	2	112.6	36.5
IN	Dearborn	4	109.6	36.4
IN	Floyd	4	140.3	52.7
IN	Floyd	7	159.6	59.9
IN	Floyd	1004	176.3	66.2
IN	Fountain	1	183.0	56.0
IN	Gibson	1	108.6	28.8
IN	Hendricks	2	41.0	19.5
IN	Jasper	2	57.0	56.9
IN	Lake	22	92.0	81.8
IN	Lake	2008	42.6	32.8
IN	La Porte	5	27.3	27.0
IN	Marion	42	92.3	36.2
IN	Marion	57	117.3	45.5
IN	Marion	73	62.0	24.4
IN	Morgan	1001	129.6	52.5
IN	Pike	5	19.3	6.2
IN	Porter	11	63.6	59.6
IN	Spencer	10	60.0	15.9
IN	Vanderburgh	12	67.3	18.9
IN	Vanderburgh	1002	35.0	9.1
IN	Vigo	18	93.6	28.4
IN	Vigo	1014	125.0	31.8
IN	Warrick	2	148.3	38.3
IN	Wayne	6	106.7	134.3
IN	Wayne	7	84.1	105.9
IA	Cerro Gordo	18	13.2	12.3
IA	Clinton	19	48.3	41.3
IA	Linn	29	46.0	48.8
IA	Linn	31	88.6	94.0
IA	Muscatine	16	122.1	91.7
IA	Muscatine	17	65.5	50.0
IA	Muscatine	20	165.1	126.2
IA	Scott	15	27.6	21.0
IA	Van Buren	6	6.9	6.8
KS	Montgomery	6	16.6	15.0
KS	Sumner	2	8.6	4.7
KS	Trego	1	4.3	2.1
KS	Wyandotte	21	50.0	33.2
KY	Boyd	17	60.3	19.1
KY	Daviess	5	71.0	20.0
KY	Greenup	7	46.0	13.3
KY	Jefferson	1041	150.6	73.4
KY	Livingston	4	53.3	53.5
KY	McCracken	1024	26.3	26.2
LA	Bossier	8	20.6	16.7
LA	Calcasieu	8	42.3	36.1
LA	East Baton Rouge	9	65.3	54.6

State	County	Monitor	2005-07	2020
LA	Ouachita	4	22.3	20.4
ME	Hancock	103	6.3	5.4
MD	Baltimore	3001	99.3	43.3
MA	Bristol	1004	64.3	21.5
MA	Hampden	16	39.0	29.7
MA	Hampshire	4002	17.0	13.0
MA	Suffolk	2	26.6	17.1
MA	Suffolk	20	23.0	14.7
MA	Suffolk	21	32.3	20.6
MA	Suffolk	40	40.3	25.9
MA	Suffolk	42	27.3	17.5
MA	Worcester	23	20.6	17.7
MN	Anoka	1002	21.3	10.4
MN	Dakota	20	18.0	7.2
MN	Dakota	423	14.0	5.6
MN	Dakota	441	7.0	2.8
MN	Dakota	442	8.0	3.2
MO	Greene	26	67.6	48.0
MO	Greene	32	25.0	17.7
MO	Greene	37	90.6	65.0
MO	Greene	40	81.3	58.3
MO	Greene	41	25.6	18.3
MO	Jackson	34	156.3	97.4
MO	Jefferson	4	350.6	285.5
MO	St. Louis	3001	49.6	34.6
MO	St. Louis city	7	56.6	40.3
MO	St. Louis city	86	67.6	47.2
MT	Yellowstone	16	40.0	46.3
MT	Yellowstone	1065	68.0	73.3
MT	Yellowstone	2005	54.6	58.8
NE	Douglas	53	89.3	87.6
NE	Douglas	55	18.6	18.2
NV	Clark	539	8.0	6.3
NH	Hillsborough	20	58.3	20.6
NH	Merrimack	1006	157.0	51.8
NH	Rockingham	14	59.6	28.3
NJ	Atlantic	5	19.0	11.7
NJ	Bergen	5001	29.3	21.6
NJ	Burlington	1001	27.6	12.8
NJ	Camden	3	38.0	16.7
NJ	Camden	1001	26.6	13.3
NJ	Cumberland	7	23.0	8.6
NJ	Gloucester	2	32.6	13.9
NJ	Hudson	6	42.0	33.7
NJ	Hudson	1002	47.6	38.2
NJ	Middlesex	2003	29.3	12.1
NJ	Morris	3001	36.0	14.4
NJ	Union	4	51.0	23.2
NM	Eddy	1004	4.6	4.6

State	County	Monitor	2005-07	2020
NM	Grant	1003	4.0	2.1
NM	San Juan	9	12.6	5.3
NM	San Juan	1005	77.0	33.0
NY	Albany	12	22.0	21.0
NY	Chautauqua	6	61.4	41.5
NY	Chautauqua	11	32.1	28.7
NY	Chemung	3	24.6	24.8
NY	Erie	5	30.6	16.4
NY	Erie	4002	118.6	75.9
NY	Essex	3	9.9	9.2
NY	Franklin	4	9.1	8.3
NY	Hamilton	5	10.3	9.2
NY	Herkimer	5	9.8	8.8
NY	Madison	6	20.0	27.2
NY	Monroe	1007	52.0	58.6
NY	New York	56	62.6	44.3
NY	Niagara	2008	21.7	13.8
NY	Onondaga	1015	17.0	39.8
NY	Putnam	5	21.9	20.0
NY	Queens	124	44.0	33.4
NY	Schenectady	3	23.0	21.9
NY	Suffolk	9	56.0	75.6
NY	Ulster	1005	15.5	15.2
NC	Beaufort	6	47.3	45.9
NC	New Hanover	6	87.6	58.4
ND	Billings	2	6.3	3.1
ND	Burke	4	29.4	29.2
ND	Cass	1004	5.5	4.1
ND	Dunn	3	11.6	8.8
ND	McKenzie	2	11.0	5.6
ND	McKenzie	104	17.6	12.3
ND	McKenzie	111	25.6	16.9
ND	Mercer	4	35.0	18.8
ND	Mercer	102	35.3	19.0
ND	Mercer	118	34.3	18.5
ND	Mercer	123	39.0	21.0
ND	Mercer	124	37.3	21.7
ND	Oliver	2	56.3	30.4
ND	Williams	103	44.3	37.3
OH	Adams	1	88.3	21.8
OH	Allen	2	22.3	19.6
OH	Ashtabula	1001	36.6	30.3
OH	Butler	4	72.0	29.0
OH	Butler	1004	57.3	23.6
OH	Clark	3	40.0	62.8
OH	Columbiana	22	121.3	42.7
OH	Cuyahoga	45	65.0	35.2
OH	Cuyahoga	60	84.3	45.7
OH	Cuyahoga	65	87.0	47.2

State	County	Monitor	2005-07	2020
OH	Franklin	34	41.6	14.9
OH	Hamilton	10	123.6	49.9
OH	Jefferson	17	175.6	52.6
OH	Lake	3	53.3	27.1
OH	Lake	3002	180.3	94.7
OH	Lawrence	6	53.3	15.4
OH	Lucas	8	68.3	32.4
OH	Lucas	24	53.3	25.3
OH	Mahoning	13	63.0	48.4
OH	Meigs	1001	98.6	25.3
OH	Scioto	13	36.6	20.6
OH	Scioto	20	51.8	17.4
OH	Summit	17	108.0	103.9
OH	Summit	22	62.0	59.6
OH	Tuscarawas	6	71.0	15.8
OK	Kay	602	40.3	67.8
OK	Kay	9010	14.6	24.3
OK	Muskogee	167	65.6	104.9
OK	Oklahoma	1037	6.6	4.8
OK	Tulsa	175	65.3	51.3
OK	Tulsa	235	61.3	48.2
OK	Tulsa	501	48.6	38.2
PA	Allegheny	10	71.3	18.4
PA	Allegheny	21	73.0	31.5
PA	Allegheny	64	142.0	60.0
PA	Allegheny	67	67.0	22.5
PA	Beaver	2	140.0	48.1
PA	Beaver	14	69.0	34.2
PA	Blair	801	58.6	57.2
PA	Bucks	12	37.3	17.3
PA	Cambria	11	86.3	34.4
PA	Centre	100	31.0	25.8
PA	Dauphin	401	64.6	15.7
PA	Erie	3	54.0	30.4
PA	Indiana	4	111.3	47.0
PA	Lackawanna	2006	40.6	20.5
PA	Lancaster	7	66.0	19.5
PA	Lawrence	15	95.0	44.0
PA	Lehigh	4	52.6	30.1
PA	Lycoming	100	50.3	7.0
PA	Mercer	100	45.3	30.6
PA	Montgomery	13	32.3	16.4
PA	Northampton	25	46.6	26.3
PA	Northampton	8000	187.0	100.4
PA	Perry	301	33.6	6.4
PA	Philadelphia	55	40.0	17.4
PA	Schuylkill	3	55.3	10.1
PA	Warren	3	63.0	63.9
PA	Warren	4	214.0	217.2

State	County	Monitor	2005-07	2020
PA	Washington	5	79.6	32.8
PA	Washington	200	79.6	20.0
PA	Washington	5001	90.0	29.6
PA	Westmoreland	8	76.6	30.3
PA	York	8	104.0	30.7
SC	Barnwell	1	17.0	19.1
SC	Charleston	3	37.3	24.4
SC	Charleston	46	23.6	9.6
SC	Georgetown	6	55.0	14.2
SC	Greenville	8	27.0	15.8
SC	Greenville	9	25.0	14.6
SC	Lexington	8	96.3	68.9
SC	Oconee	1	20.0	17.7
SC	Richland	7	28.6	20.1
SC	Richland	1003	36.3	25.5
SD	Custer	132	4.3	3.2
SD	Jackson	1	3.6	1.5
SD	Minnehaha	7	18.0	15.2
TN	Blount	2	196.3	60.0
TN	Blount	6	84.9	25.6
TN	Bradley	102	85.3	80.2
TN	Davidson	11	23.6	26.1
TN	Montgomery	6	53.0	66.1
TN	Montgomery	106	115.6	144.3
TN	Shelby	46	65.3	49.0
TN	Shelby	1034	81.3	56.5
TN	Sullivan	7	170.6	88.2
TN	Sullivan	9	141.8	73.3
TX	Dallas	69	11.6	10.3
TX	El Paso	37	9.3	9.1
TX	El Paso	53	12.6	12.4
TX	Galveston	5	59.0	42.9
TX	Gregg	1	78.3	38.9
TX	Harris	46	34.0	27.4
TX	Harris	51	31.0	24.9
TX	Harris	62	55.3	43.7
TX	Harris	70	68.6	54.3
TX	Harris	1035	74.6	58.9
TX	Harris	1050	17.3	12.7
TX	Jefferson	9	123.0	98.9
TX	Jefferson	11	94.6	74.9
TX	Kaufman	5	15.3	13.4
TX	Nueces	25	24.0	12.4
TX	Nueces	26	8.0	4.1
TX	Nueces	32	36.0	18.7
UT	Davis	4	22.6	24.1
UT	Salt Lake	1001	32.0	34.5
VT	Rutland	2	48.2	45.5
VA	Charles City	2	88.6	24.9

State	County	Monitor	2005-07	2020
VA	Fairfax	5	25.6	6.8
VA	Fairfax	1005	37.0	8.2
VA	Fairfax	5001	37.3	14.6
VA	Rockingham	3	14.6	13.0
VA	Alexandria city	9	55.3	12.2
VA	Hampton city	4	64.0	46.3
VA	Richmond city	24	62.0	15.2
WV	Brooke	5	150.3	45.0
WV	Brooke	7	164.6	49.3
WV	Brooke	11	155.3	46.5
WV	Cabell	6	41.6	7.4
WV	Hancock	5	164.0	56.3
WV	Hancock	7	132.0	42.4
WV	Hancock	8	115.3	40.6
WV	Hancock	9	136.6	43.9
WV	Hancock	15	121.3	42.7
WV	Hancock	1004	135.6	43.6
WV	Kanawha	10	88.0	22.4
WV	Marshall	1002	155.0	41.8
WV	Monongalia	3	171.3	41.5
WV	Wood	1002	130.6	37.8
WI	Brown	5	74.3	64.7
WI	Oneida	996	179.0	175.3

Chapter 4: Emissions Controls Analysis – Design and Analytical Results

Synopsis

This chapter documents the illustrative emission control strategy we applied to simulate attainment with the alternative standards being analyzed for the final SO_2 NAAQS. Section 4.1 describes the approach we followed to select emissions controls to simulate attainment in each geographic area of analysis. Section 4.2 summarizes the emission reductions we simulated in each area based on current knowledge of identified emission controls, while Section 4.3 presents the air quality impacts of these emissions reductions. Section 4.4 discusses the application of additional controls, beyond the level of control already assumed to be in place for the analysis year[1], that we estimate will be necessary to reach attainment in certain monitor areas. Section 4.5 discusses key limitations in the approach we used to estimate the optimal control strategies for each alternative standard.

The final rule will set a new short-term SO_2 primary standard based on the average of the 99th percentile of 1-hour daily maximum concentrations from three consecutive years of data. This new standard will be set at 75 parts per billion (ppb). OMB Circular A-4 requires the RIA to contain, in addition to analysis of the impacts of the final NAAQS, analysis of a level more stringent and a level less stringent than the final NAAQS. For a more stringent standard level, we chose an alternative primary standard of 50 parts per billion (ppb). We also include analyses for a less stringent standard, 100 ppb.

For the range of alternative standards, we analyzed the impact that additional emissions controls applied to numerous sectors would have on predicted ambient SO_2 concentrations, incremental to the baseline set of controls. Thus the analysis for a revised standard focuses specifically on incremental improvements beyond the current standards, and uses control options that might be available to states for application by 2020. The hypothetical control strategy presented in this RIA is one illustrative option for achieving emissions reductions to move towards a national attainment of a tighter standard. It is not a recommendation for how a tighter SO_2 standard should be implemented, and states will make all final decisions regarding implementation strategies once a final NAAQS has been set.

Generally, we expect that the nation will be able to make significant progress towards attainment of a tighter SO_2 NAAQS without the addition of new controls beyond those already being planned for the attainment of existing $PM_{2.5}$ standards by the year 2020. As States

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[1] Note that the baseline or starting point for this analysis includes rules that are already "on the books" and will take affect prior to the analysis year, as well as control strategies applied in the recent PM and Ozone NAAQS RIAs.

develop their plans for attaining these existing standards, they are likely to consider adding controls to reduce sulfur dioxide, as SO_2 is a precursor to both $PM_{2.5}$. In addition, proposed standards such as the Portland cement NESHAP, the ICI boilers NESHAPs, and the eventual rule to replace the existing CAIR may also yield in total considerable additional reductions of SO_2 emissions if they are implemented as proposed. These controls will also directly help areas meet a tighter SO_2 standard.

As part of our economic analysis of the tighter SO_2 standard, our 2020 analysis baseline assumes that States will put in place the necessary control strategies to attain the current $PM_{2.5}$ standards. The cost of these control strategies was included in the RIAs for those rulemakings. We do not include the cost of those controls in this analysis, in order to prevent counting the cost of installing and operating the controls twice. Of course, the health and environmental benefits resulting from installation of those controls were attributed to attaining those standards, and are not counted again for the analysis of this SO_2 standard.

In addition, we include the SO_2 control requirements for Category 3 (C3) marine vessels that will be affected by a new mobile source rule promulgated by EPA in December 2009.[2] These requirements call for changes in the diesel fuel program to allow for use of lower sulfur fuel (1,000 ppm sulfur content) in U.S.-flagged C3 marine vessels beginning in 2011. Reductions of SO_2 associated with this final rule are included in our 2020 analysis baseline. Thus, we estimate no costs or benefits associated with these reductions.

It is important to note also that this analysis does not attempt to estimate attainment or nonattainment for any areas of the country other than those counties currently served by one of the 349 monitors in the current network. Chapter 3 explains that the current network is focused on longer terms indicators that that included in this final rule.

Finally, we note that because it was not possible, in this analysis, to bring all areas into attainment with the alternative standards in all areas using only identified (or known) controls, EPA conducted a second step in the analysis, and estimated the cost of further tons of emission reductions needed to attain the alternative primary NAAQS. It is uncertain what controls States would put in place to attain a tighter standard, since additional abatement strategies are not currently recognized as being commercially available. We should also note that because of data and resource limitations, we are not able to adequately represent in this analysis the impacts of some local emission control programs such as discussed in Chapter 3.

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[2] Control of Emissions from New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder. Signed on December 18, 2009. For more information on this final rule and its RIA, please refer to http://www.epa.gov/otaq/oceanvessels.htm.

4.1 Developing the Identified Control Strategy Analysis

The 2020 baseline air quality estimates revealed that 27 monitors in 24 counties had projected design values exceeding 75 ppb. We then developed a hypothetical control strategy that could be adopted to bring the current highest emitting monitor in each of those counties into attainment with a primary standard of 75 ppb, as well as additional target levels of 50 ppb and 100 ppb, by 2020. (For more information on the development of the air quality estimates for this analysis see Chapter 3.) Controls for three emissions sectors were included in the control analysis: Non-Electricity Generating Unit Point Sources (nonEGU), Non-Point Area Sources (Area), and Electricity Generating Unit Point Sources (EGU). Each of these sectors is defined below for clarity.

- NonEGU point sources as defined in the National Emissions Inventory (NEI) are stationary sources that emit 100 tons per year or more of at least one criteria pollutant. NonEGU point sources are found across a wide variety of industries, such as chemical manufacturing, cement manufacturing, petroleum refineries, and iron and steel mills.
- Area Sources[3] are stationary sources that are too numerous or whose emissions are too small to be individually included in a stationary source emissions inventory. Area sources are the activities where aggregated source emissions information is maintained for the entire source category instead of each point source, and are reported at the county level.
- Electricity Generating Unit Point Sources are stationary sources of 25 megawatts (MW) capacity or greater producing and selling electricity to the grid, such as fossil-fuel-fired boilers and combustion turbines.

It should be noted that no additional SO_2 controls beyond our baseline are applied to onroad and nonroad mobile sources because mobile source measures to reduce sulfur content from diesel engine rules will be well-applied in onroad and nonroad mobile source fleets by 2020, and thus there is little capability to achieve further reductions for this analysis beyond those described in this report.

We began the control strategy analysis by applying controls to EGUs first before applying controls to other sources. We applied controls in this sequence for the following reasons: 1) there are many more SO_2 emissions from EGUs than from non-EGU sources in the areas included in this analysis, and 2) SO_2 reductions from EGUs are less costly than from other

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[3] Area Sources include the nonpoint emissions sector only.

source categories included in this analysis. Chapter 6 provides a table showing that the EGU control costs for SO_2 as estimated for this analysis have a lower annual cost/ton compared to those from the non-EGU point and area source categories.

The air quality impact of the needed emissions reductions was calculated using impact ratios as discussed further in Chapter 3. The results of analyzing the control strategy indicate that there were four areas projected not to attain 75 ppb in 2020 using all identified control measures. To complete the analysis, EPA then extrapolated the additional emission reductions required to reach attainment. The methodology used to develop those estimates and those calculations are presented in Section 4.4.

4.1.1 Controls Applied for EGU Sector

The baseline in this RIA for EGUs accounts for extensive reductions in SO_2 emissions from EGUs as implemented in the Clean Air Interstate Rule (CAIR).[4] While the US District Court for District of Columbia has remanded the CAIR, it still is in full effect. The Agency is working at this time on a proposal to replace the CAIR, but that proposal is not yet complete. No additional controls for SO_2 from EGUs are implemented in the baseline.

The Integrated Planning Model (IPM) was used to develop the baseline emissions for the control strategy applied for the alternative standards. Historically, EPA has used the IPM model to assess the cost and effectiveness of additional EGU controls for a large number of rulemakings (e.g., CAIR, NOx SIP call, Ozone NAAQS, etc.). For this RIA, we applied controls on a unit by unit basis to obtain reductions from units that contribute to nonattainment at violating monitors in 2020. The end result of this approach mimics an approach which could be used by individual states as they try to apply targeted controls on EGUs which affect attainment in a specific area.

In this analysis, EGU controls were applied to uncontrolled coal-fired units of size 25 MW and larger within the 50 km radius of violating monitors. Each unit was retrofitted with a Wet Flue Gas Desulfurization (FGD) scrubber with 95 percent SO_2 reduction efficiency. This control measure is applicable to coal-fired EGUs with unit capacities above 25 MW.[5] More

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[4] For more information on the CAIR rule, please refer to http://www.epa.gov/airmarkt/progsregs/cair/.

[5] Costs of FGD scrubber applications increase progressively as EGU capacity approaches 25 MW. At an capital cost of more than $1000/kW, it is typically more economical to retire a unit than to operate it with a scrubber. It is possible to duct emissions from more than one EGU to a single scrubber, but that approach is not included in this analysis.

information on EGU SO_2 measures, particularly for EGUs with 100 MW or larger capacity, can be found in the documentation for the IPM version used for this RIA.[6]

4.1.2 Controls Applied for the NonEGU Point and Area Sectors

NonEGU point and Area control measures were identified using AirControlNET 4.2 as well as the Control Strategy Tool[7] (CoST). To reduce nonEGU point SO_2 emissions, least cost control measures were identified for emission sources within 50 km of the violating monitor (see Chapter 3 for rationale). Area source emissions data are generated at the county level, and therefore controls for this emission sector were applied to the county containing the violating monitor.

The SO_2 emission control measures used in this analysis are similar to those used in the $PM_{2.5}$ RIA prepared about three years ago. FGD scrubbers can achieve 95% control of SO_2 for non-EGU point sources and for utility boilers. Spray dryer absorbers (SDA) are another commonly employed technology, and SDA can achieve up to 90% control of SO_2. For specific source categories, other types of control technologies are available that are more specific to the sources controlled. The following table lists these technologies. For more information on these technologies, please refer to the AirControlNET 4.2 control measures documentation report.[8]

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[6] Documentation on the version of IPM used for this RIA can be found at http://www.epa.gov/airmarkt/progsregs/epa-ipm/index.html.

[7] See http://www.epa.gov/ttn/ecas/cost.htm for a description of CoST.

[8] For a complete description of AirControlNET control technologies see AirControlNET 4.2 control measures documentation report, prepared by E.H. Pechan and Associates. May 2008. More information on AirControlNET (in this case, version 4.1) and the control technologies included in the tool are available at http://www.epa.gov/ttn/ecas/AirControlNET.htm.

Table 4-1: Example SO_2 Control Measures for Non-EGU Point Sources Applied in Identified Control Measures Control Strategy Analyses[a]

Control Measure	Sectors to which These Control Measures Can Be Applied	Control Efficiency (percent)	Average Annualized Cost/ton (2006$)
Wet and Dry FGD scrubbers and SDA	ICI boilers—all fuel types, kraft pulp mills, Mineral Products (e.g., Portland cement plants (all fuel types), primary metal plants, petroleum refineries	95—FGD scrubbers, 90 - for SDA	$800-$8,000—FGD $900 – 7,000—SDA
Increase percentage sulfur conversion to meet sulfuric acid NSPS (99.7% reduction)	Sulfur recovery plants	75 to 95	$4,000
Sulfur recovery and/or tail gas treatment	Sulfuric Acid Plants	95-98	$1,000 – 4,000
Cesium promoted catalyst	Sulfuric Acid Plants with Double-Absorption process	50%	$1,000

Sources: AirControlNET 4.2 control measures documentation report, May 2008, NESCAUM Report on Applicability of NOx, SO_2, and PM Control Measures to Industrial Boilers, November 2008 available at http://www.nescaum.org/documents/ici-boilers-20081118-final.pdf , and Comprehensive Industry Document on Sulphuric Acid Plant, Govt. of India Central Pollution Control Board, May 2007. The estimates for these control measures reflect applications of control where there is no SO_2 control measure currently operating except for the Cesium promoted catalyst.

In applying these SO_2 controls, we employ a decision rule in which we do not apply controls to any non-EGU source with 50 tons/year of emissions or less. This decision rule is the same one we employed for such sources in the $PM_{2.5}$ RIA completed four years ago.[9] The reason for applying this decision rule is based on a finding that most point sources with emissions of this level or less had SO_2 controls already on them. This decision rule aids in gap filling for a lack of information regarding existing controls on nonEGU sources. In addition, we also apply the decision rule that we do not apply SO_2 nonEGU point source controls that yield emission reductions of 50 tons/year or less. We apply this decision rule in order to reduce the number the sources affected our non-EGU control strategies to those sources whose reductions are relatively more cost-effective.

The analysis for non-EGUs mostly applied controls to the following source categories: industrial boilers, commercial and institutional boilers, sulfuric acid plants (both standalone and at other facilities such as copper and lead smelters), primary metal plants (iron and steel mills,

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[9] $PM_{2.5}$ RIA, Chapter 3, p. 3-10. This RIA was completed in October, 2006 and is available at http://www.epa.gov/ttn/ecas/ria.html.

lead smelters), mineral products (primarily cement kilns) and petroleum refineries. These source categories are the most prevalent SO_2 emitters in the areas included in this analysis.

4.1.3 Data Quality for this Analysis

The estimates of emission reductions associated with our control strategies above are subject to important limitations and uncertainties. EPA's analysis is based on its best judgment for various input assumptions that are uncertain. As a general matter, the Agency selects the best available information from available engineering studies of air pollution controls and has set up what it believes is the most reasonable framework for analyzing the cost, emission changes, and other impacts of regulatory control.

4.2 SO_2 Emission Reductions Achieved with Identified Controls Analysis

We identified illustrative control strategies that might be employed to reduce emissions to bring air quality into compliance with the alternative standard being analyzed. As part of this exercise, we considered the cost-effectiveness of various control options and selected the lowest cost controls, based on available cost information. Applying identified control measures, we were able to illustrate attainment for most, but not all of the areas. [10]

Table 4.2 presents the emission reductions achieved through applying identical control measures, both by sector and in total. As this table reveals, a majority of the emission reductions were achieved through EGU emission controls. As indicated in this table, the estimate emission reductions from the identified controls applied in this analysis under the 75 ppb alternative standard in 2020 are 372,000 tons. About 260,000 tons of the reductions are from EGUs, and 112,000 are from non-EGU point sources. For the other alternative standards, the total emission reductions in 2020 are estimated to range from 186,000 tons for the 100 ppb standard to 803,000 tons for the 50 ppb standard. For all of these standards, this analysis shows that roughly 60 to 70 percent of these reductions are from EGUs. Most of the remaining reductions obtained come from non-EGU point sources. Reductions from area sources are generally a very small portion of those estimated except for the 50 ppb alternative standard, where 1.8 percent of reductions come from this sector.

Table 4.2: Emission Reductions from Identified Controls in 2020 in Total and by Sector (Tons) [a] for Each Alternative Standard

	50 ppb	75 ppb	100 ppb
Total Emission Reductions from Identified Controls:[b]	800,000	370,000	190,000
EGUs	540,000	260,000	110,000
Non-EGUs	250,000	110,000	79,000
Area Sources	15,000	200	100

[a] All estimates rounded to two significant figures. As such, totals may not sum down columns.
[b] These values represent emission reductions for the identified control strategy analysis. There were locations not able to attain the alternative standard being analyzed with identified controls only.

Table 4.3 presents the emission reductions by individual non-EGU point source category in 2020. As this table shows, the majority of reductions are from industrial boilers for all alternative standards except for 100 ppb. The percentage of non-EGU point source reductions from industrial boilers ranges from 50 (50 ppb) to 33 (100 ppb). Reductions from primary metal

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[10] As will be discussed below, the application of identified controls was insufficient to bring all monitor areas into compliance with the alternative standards.

units provide most of the reductions at 100 ppb (59 percent) and this source category has the next highest percent of reductions for the other alternative standards (21 percent at 50 ppb, 43 percent at 75 ppb).

Table 4.3: Emission Reductions from Identified Controls By Non-EGU Point Source Category in 2020 in Total (Tons)[a] for Each Alternative Standard

	50 ppb	75 ppb	100 ppb
Total Non-EGU Emission Reductions from Identified Controls:[b]	246,000	112,000	79,000
Industrial Boilers	124,000	49,000	26,000
Sulfuric Acid Plants	3,000	2,000	1,000
Commercial/Institutional Boilers	20,000	4,000	4,000
Primary Metal Products	52,000	48,000	47,000
Petroleum Refineries	23,000	6,000	1,000
Mineral Products	22,000	5,000	600

[a] All estimates rounded to two significant figures. As such, totals may not sum down columns.
[b] These values represent emission reductions for the identified control strategy analysis. There were locations not able to attain the alternative standard being analyzed with identified controls only.

Table 4.4 presents the SO_2 emissions reductions realized in each geographic area under the control strategies applied for the final standard of 75 ppb and also for the other two alternative standards.

Table 4.4: Emission Reductions by County in 2020 for Each Alternative Standard Analyzed [a]

State	County	50 ppb	75 ppb	100 ppb
Arizona	Gila Co	9,000	9,000	9,000
Colorado	Denver Co	10,000	-	-
Connecticut	New Haven Co	8,000	-	-
Florida	Duval Co	5,100	-	-
Florida	Hillsborough Co	1,300	-	-
Georgia	Chatham Co	19,000	5,400	-
Idaho	Bannock Co	590	-	-
Illinois	Cook Co	39,000	-	-
Illinois	Madison Co	29,000	14,000	-
Illinois	St Clair Co	82,000	-	-
Illinois	Sangamon Co	22,000	11,000	-
Illinois	Tazewell Co	17,000	6,700	-
Indiana	Floyd Co	15,000	-	-
Indiana	Fountain Co	9,000	-	-
Indiana	Jasper Co	21,000	-	-
Indiana	Lake Co	65,000	20,000	-
Indiana	Morgan Co	3,300	-	-
Indiana	Porter Co	50,000	-	-

Indiana	Wayne Co	10,000	10,000	9,800
Iowa	Linn Co	9,200	4,700	-
Iowa	Muscatine Co	27,000	21,000	11,000
Kentucky	Jefferson Co	16,000	-	-
Kentucky	Livingston Co	4,900	-	-
Louisiana	East Baton Rouge Par	12,000	-	-
Missouri	Greene Co	3,000	-	-
Missouri	Jackson Co	25,000	13,000	-
Missouri	Jefferson Co	130,000	130,000	120,000
Montana	Yellowstone Co	6,100	-	-
Nebraska	Douglas Co	24,000	24,000	-
New Hampshire	Merrimack Co	2,700	-	-
New York	Erie Co	8,200	3,200	-
New York	Monroe Co	12,000	-	-
New York	Suffolk Co	11,000	4,400	-
North Carolina	New Hanover Co	6,200	-	-
Ohio	Clark Co	6,000	-	-
Ohio	Jefferson Co	12,000	-	-
Ohio	Lake Co	34,000	15,000	-
Ohio	Summit Co	22,000	15,000	3,100
Oklahoma	Kay Co	18,000	-	-
Oklahoma	Muskogee Co	52,000	35,000	17,000
Oklahoma	Tulsa Co	15,000	-	-
Pennsylvania	Allegheny Co	8,800	-	-
Pennsylvania	Blair Co	4,300	-	-
Pennsylvania	Northampton Co	21,000	12,000	-
Pennsylvania	Warren Co	6,100	6,100	6,100
South Carolina	Lexington Co	7,800	-	-
Tennessee	Blount Co	4,000	-	-
Tennessee	Bradley Co	11,000	1,200	-
Tennessee	Montgomery Co	1,000	1,000	1,000
Tennessee	Shelby Co	4,900	-	-
Tennessee	Sullivan Co	24,000	8,400	-
Texas	Harris Co	28,000	-	-
Texas	Jefferson Co	12,000	7,000	-
West Virginia	Hancock Co	25,000	-	-
Wisconsin	Brown Co	11,000	-	-
Wisconsin	Oneida Co	7,000	7,000	7,000

[a] All estimates rounded to two significant figures.

4.3 Impacts Using Identified Controls

As discussed in Chapter 3, we estimated the overall change in ambient air quality achieved as a result of each of the control strategies identified above using an impact ratio of emission reductions to air quality improvement. Table 4.5 presents a detailed breakdown of the estimated ambient SO_2 concentrations in 2020 at each of the counties that do not reach attainment under one or more of the alternative standards.

According to the data presented in Table 4.5, 20 of the 24 monitor areas are expected to reach attainment with a standard of 75 ppb following implementation of the identified control strategy. For four areas, identified controls are not sufficient to reach attainment with the standard of 75 ppb. For the areas projected to violate the NAAQS with the application of identified controls, we assume that emission reductions beyond identified controls will be applied, as discussed further below.

Table 4.5: 2020 SO_2 Design Values after Application of Identified Controls for Alternative Standards

State	County	50 ppb	75 ppb	100 ppb
Arizona	Gila Co	188.9	188.9	188.9
Colorado	Denver Co	50.3		
Connecticut	New Haven Co	46.9		
Florida	Duval Co	50.4		
Florida	Hillsborough Co	52.5		
Georgia	Chatham Co	34.4	72.1	
Idaho	Bannock Co	41.2		
Illinois	Cook Co	39.6		
Illinois	Madison Co	57.0	74.0	
Illinois	St Clair Co	20.1		
Illinois	Sangamon Co	35.9	67.5	
Illinois	Tazewell Co	47.9	73.5	
Indiana	Floyd Co	53.2		
Indiana	Fountain Co	46.3		
Indiana	Jasper Co	33.6		
Indiana	Lake Co	49.1	71.5	
Indiana	Morgan Co	47.8		
Indiana	Porter Co	37.4		
Indiana	Wayne Co	98.1	98.1	100.2
Iowa	Linn Co	50.8	71.7	
Iowa	Muscatine Co	50.0	68.3	96.9
Kentucky	Jefferson Co	54.6		
Kentucky	Livingston Co	50.2		
Louisiana	East Baton Rouge Par	48.6		
Missouri	Greene Co	44.5		
Missouri	Jackson Co	47.3	71.9	

Missouri	Jefferson Co	66.4	73.8	78.7
Montana	Yellowstone Co	45.8		
Nebraska	Douglas Co	47.2	47.2	
New Hampshire	Merrimack Co	42.6		
New York	Erie Co	51.5	66.4	
New York	Monroe Co	46.5		
New York	Suffolk Co	66.4	72.0	
North Carolina	New Hanover Co	44.7		
Ohio	Clark Co	50.7		
Ohio	Jefferson Co	46.0		
Ohio	Lake Co	37.3	70.4	
Ohio	Summit Co	59.2	74.6	97.6
Oklahoma	Kay Co	41.2		
Oklahoma	Muskogee Co	42.2	63.2	84.2
Oklahoma	Tulsa Co	28.3		
Pennsylvania	Allegheny Co	57.0		
Pennsylvania	Blair Co	50.1		
Pennsylvania	Northampton Co	49.8	70.4	
Pennsylvania	Warren Co	118.8	118.8	118.8
South Carolina	Lexington Co	39.2		
Tennessee	Blount Co	52.9		
Tennessee	Bradley Co	33.2	75.2	
Tennessee	Montgomery Co	139.5	139.5	139.5
Tennessee	Shelby Co	46.0		
Tennessee	Sullivan Co	45.2	73.3	
Texas	Harris Co	42.4		
Texas	Jefferson Co	49.6	69.3	
West Virginia	Hancock Co	42.7		
Wisconsin	Brown Co	47.2		
Wisconsin	Oneida Co	47.1	47.1	47.1

Table 4.6 Number of Areas Projected to be in Nonattainment for Each Alternative Standard After Application of Identified Controls in 2020[a]

	50 ppb	75 ppb	100 ppb
Number of Areas Needing Emission Reductions Beyond Identified Controls	16	4	3

[a] There are 56 areas included in this analysis.

4.4 Emission Reductions Needed Beyond Identified Controls

As shown through the identified control strategy analysis, there were not enough identified controls for every area in the analysis to achieve attainment with neither the 75 ppb final standard nor the other alternative standards in 2020. Therefore additional emission reductions will be needed for these areas to attain these alternative standards. Table 4.7 shows the emission reductions needed beyond identified controls for counties to attain the alternative standards being analyzed. The total emission reductions for full attainment of each alternative standard are also included in this table. Table 4.8 presents the emission reductions needed for each area beyond identified controls for each alternative standard. Chapter 6 presents the discussion of extrapolated costs associated with the emission reductions needed beyond identified controls.

Table 4.7: Total Emission Reductions and those from Extrapolated Controls in 2020 in Total and by Sector (Tons)[a] for Each Alternative Standard

	50 ppb	75 ppb	100 ppb
Total Emission Reductions from Identified and Unidentified Controls	920,000	350,000	170,000
Total Emission Reductions from Unidentified Controls	110,000	33,000	18,000
Unidentified Reductions from EGUs	33,000	5,000	-
Unidentified Reductions from non-EGUs	54,000	22,000	15,000
Unidentified Reductions from Area Sources	19,000	6,400	3,000

[a] All estimates rounded to two significant figures.

Table 4.8: Emission Reductions Needed Beyond Identified Controls in 2020

State	County	50 ppb	75 ppb	100 ppb
Arizona	Gila Co	13,000	11,000	8,300
Colorado	Denver Co	-	-	-
Connecticut	New Haven Co	-	-	-
Florida	Duval Co	-	-	-
Florida	Hillsborough Co	2,800	-	-
Georgia	Chatham Co	-	-	-
Idaho	Bannock Co	-	-	-
Illinois	Cook Co	-	-	-
Illinois	Madison Co	5,800	-	-
Illinois	St Clair Co	-	-	-
Illinois	Sangamon Co	-	-	-
Illinois	Tazewell Co	-	-	-
Indiana	Floyd Co	3,200	-	-
Indiana	Fountain Co	-	-	-
Indiana	Jasper Co	-	-	-
Indiana	Lake Co	-	-	-
Indiana	Morgan Co	-	-	-
Indiana	Porter Co	-	-	-
Indiana	Wayne Co	14,000	6,500	-
Iowa	Linn Co	84	-	-
Iowa	Muscatine Co	-	-	-
Kentucky	Jefferson Co	3,500	-	-
Kentucky	Livingston Co	-	-	-
Louisiana	East Baton Rouge Par	-	-	-

Missouri	Greene Co	-	-	-
Missouri	Jackson Co	-	-	-
Missouri	Jefferson Co	9,500	-	-
Montana	Yellowstone Co	-	-	-
Nebraska	Douglas Co	-	-	-
New Hampshire	Merrimack Co	-	-	-
New York	Erie Co	360	-	-
New York	Monroe Co	-	-	-
New York	Suffolk Co	19,000	-	-
North Carolina	New Hanover Co	-	-	-
Ohio	Clark Co	130	-	-
Ohio	Jefferson Co	-	-	-
Ohio	Lake Co	-	-	-
Ohio	Summit Co	4,400	-	-
Oklahoma	Kay Co	-	-	-
Oklahoma	Muskogee Co	-	-	-
Oklahoma	Tulsa Co	-	-	-
Pennsylvania	Allegheny Co	20,000	-	-
Pennsylvania	Blair Co	-	-	-
Pennsylvania	Northampton Co	-	-	-
Pennsylvania	Warren Co	4,300	2,700	1,100
South Carolina	Lexington Co	-	-	-
Tennessee	Blount Co	1,400	-	-
Tennessee	Bradley Co	-	-	-
Tennessee	Montgomery Co	19,000	13,000	8,200
Tennessee	Shelby Co	-	-	-
Tennessee	Sullivan Co	-	-	-
Texas	Harris Co	-	-	-
Texas	Jefferson Co	-	-	-
West Virginia	Hancock Co	-	-	-
Wisconsin	Brown Co	-	-	-
Wisconsin	Oneida Co	-	-	-

[a] All estimates rounded to two significant figures.

4.5 Key Limitations

The estimates of emission reductions associated with the control strategies described above are subject to important limitations and uncertainties. We summarize these limitations as follows:

- *Actual State Implementation Plans May Differ from our Simulation*: In order to reach attainment with the final NAAQS, each state will develop its own implementation plan implementing a combination of emissions controls that may differ from those simulated in this analysis. This analysis therefore represents an approximation of the emissions reductions that would be required to reach attainment and should not be treated as a precise estimate.

- *Use of Existing CMAQ Model Runs:* This analysis represents a screening level analysis. We did not conduct new regional scale modeling specifically targeting SO_2. More explanation on the screening level analysis done for this RIA can be found in Chapter 3.

- *Analysis Year of 2020:* Data limitations necessitated the choice of an analysis year of 2020, as opposed to the presumptive implementation year of 2017. Emission inventory projections are available for 5-year increments; i.e. we have inventories for 2015 and 2020, but not 2017. In addition, the CMAQ model runs upon which we relied were also based on an analysis year of 2020.

- *Unidentified controls*: We have limited information on available controls for some of the monitor areas included in this analysis. For a number of small non-EGU and area sources, there is little or no information available on SO_2 controls.

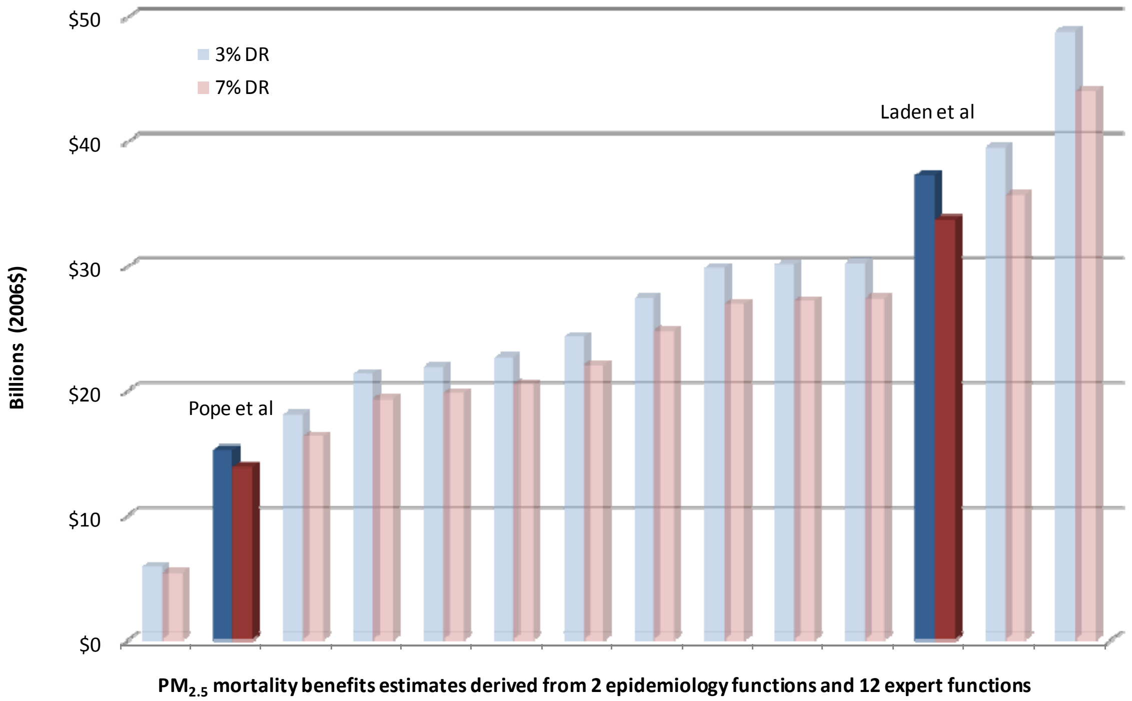
Chapter 5: Benefits Analysis Approach and Results

Synopsis

EPA estimated the monetized human health benefits of reducing cases of morbidity among populations exposed to SO_2 and cases of morbidity and premature mortality among populations exposed to $PM_{2.5}$ in 2020 for the selected standard and alternative standard levels in 2006$. Because SO_2 is also a precursor to $PM_{2.5,}$ reducing SO_2 emissions in the projected non-attainment areas will also reduce $PM_{2.5}$ formation, human exposure and the incidence of $PM_{2.5}$-related health effects. For the selected SO_2 standard at 75 ppb (99th percentile, daily 1-hour maximum), the total monetized benefits would be $15 to $37 billion at a 3% discount rate and $14 to $33 billion at a 7% discount rate. For an SO_2 standard at 50 ppb, the total monetized benefits would be $34 to $83 billion at a 3% discount rate and $31 to $75 billion at a 7% discount rate. For an SO_2 standard at 100 ppb, the total monetized benefits would be $7.4 to $18 billion at a 3% discount rate and $6.7 to $16 billion at a 7% discount rate.

These estimates reflect EPA's most current interpretation of the scientific literature and are consistent with the methodology used for the proposal RIA. These benefits are incremental to an air quality baseline that reflects attainment with the 2008 ozone and 2006 $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS). More than 99% of the total dollar benefits are attributable to reductions in $PM_{2.5}$ exposure resulting from SO_2 emission controls. Higher or lower estimates of benefits are possible using other assumptions; examples of this are provided in Figure 5.1 for the selected standard of 75 ppb. Methodological limitations prevented EPA from quantifying the impacts to, or monetizing the benefits from several important benefit categories, including ecosystem effects from sulfur deposition, improvements in visibility, and materials damage. Other direct benefits from reduced SO_2 exposure have not been quantified, including reductions in premature mortality.

Figure 5.1: Total Monetized Benefits (SO_2 and $PM_{2.5}$) of Attaining 75 ppb in 2020*



*This graph shows the estimated total monetized benefits in 2020 for the selected standard of 75 ppb using the no-threshold model at discount rates of 3% and 7% using effect coefficients derived from the Pope et al. study and the Laden et al. study, as well as 12 effect coefficients derived from EPA's expert elicitation on PM mortality. The results shown are not the direct results from the studies or expert elicitation; rather, the estimates are based in part on the concentration-response function provided in those studies. Graphs for alternative standards would show a similar pattern.

5.1 Introduction

This chapter documents our analysis of health benefits expected to result from achieving alternative levels of the SO_2 NAAQS in 2020, relative to baseline ambient concentrations that represent attainment with previously promulgated regulations, including the 2008 ozone and 2006 $PM_{2.5}$ NAAQS. We first describe our approach for estimating and monetizing the health benefits associated with reductions of SO_2. Next, we provide a summary of our results, including an analysis of the sensitivity of several assumptions in our model. We then estimate the $PM_{2.5}$ co-benefits from controlling SO_2 emissions. Finally, we discuss the key results of the benefits analysis and indicate limitations and areas of uncertainty in our approach.

5.2 Primary Benefits Approach

This section presents our approach for estimating avoided adverse health effects due to SO_2 exposure in humans resulting from achieving alternative levels of the SO_2 NAAQS, relative to a baseline concentration of ambient SO_2. First, we summarize the scientific evidence concerning potential health effects of SO_2 exposure, and then we present the health endpoints we selected for our primary benefits estimate. Next, we describe our benefits model, including the key input data and assumptions. Finally, we describe our approach for assigning an economic value to the SO_2 health benefits. The approach for estimating the benefits associated with exposure to PM is described in section 5.7.

We estimated the economic benefits from annual avoided health effects expected to result from achieving alternative levels of the SO_2 NAAQS (the "control scenarios") in the year 2020. We estimated benefits in the control scenarios relative to the incidence of health effects consistent with the ambient SO_2 concentration expected in 2020 (the "baseline"). Note that this "baseline" reflects emissions reductions and ambient air quality improvements that we anticipate will result from implementation of other air quality rules, including compliance with previously promulgated regulations, including the 2008 ozone and 2006 $PM_{2.5}$ NAAQS.[1]

We compare benefits across three alternative SO_2 NAAQS levels: 50 ppb, 75 ppb, and 100 ppb (99th percentile). Consistent with EPA's approach for RIA benefits assessments, we estimate the health effects associated with an incremental difference in ambient concentrations between a baseline scenario and a pollution control strategy. As indicated in Chapter 4, several areas of the country may not be able to attain the alternative standard levels using known pollution control methods. For this reason, we provide an estimate of the benefits associated with partially attaining the standard using known controls as well as the full attainment results in Table 5.13 of this chapter. Because some areas require emission reductions from unknown sources to attain the various standards, the results are sensitive to assuming full attainment. All of the other results tables in this chapter assume full attainment with the various standard levels. The full attainment results include extrapolated tons from unknown controls, which were spread across the sectors in proportion to the emissions in the county.[2]

5.3 Overview of analytical framework for benefits analysis

5.3.1 Benefits Model

For the SO_2 benefits analysis, we use the Environmental Benefits Mapping and Analysis Program (BenMAP, version 3) (Abt Associates, 2008) to estimate the health benefits occurring as a result of implementing alternative SO_2 NAAQS levels. Although EPA has used BenMAP

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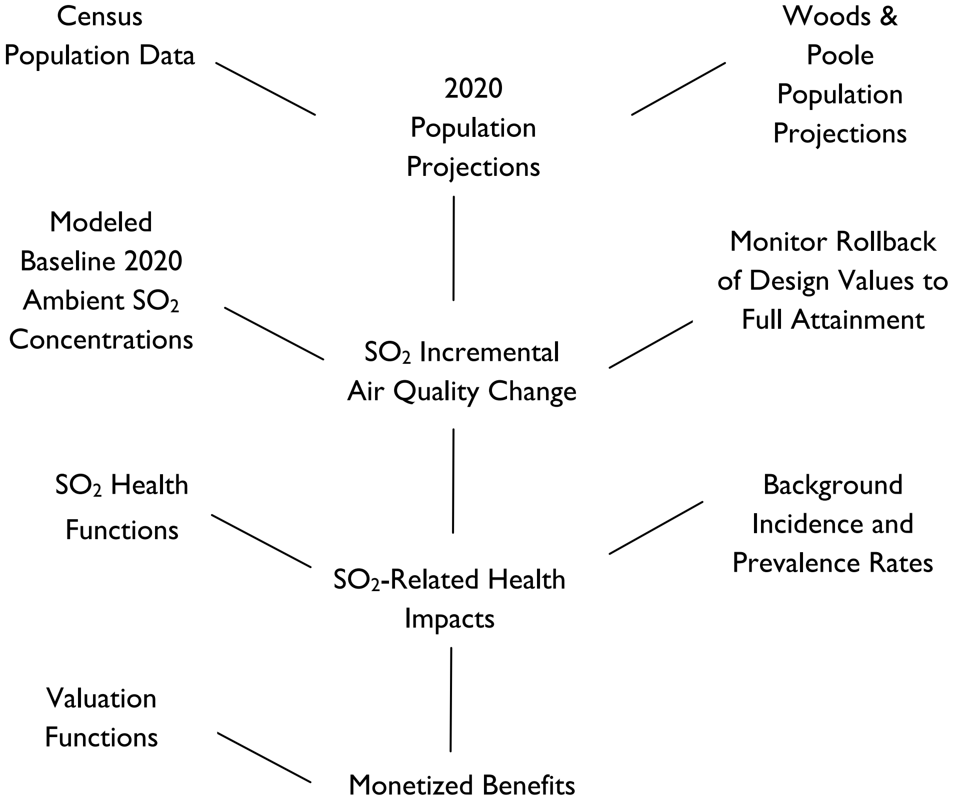
[1] See Chapter 2 of this RIA for more information on the rules incorporated into the baseline.

[2] See Chapter 4 of this RIA for more information on the extrapolated tons estimated to reach full attainment.

extensively to estimate the health benefits of reducing exposure to $PM_{2.5}$ and ozone in previous RIAs, the proposal RIA was the first RIA in which EPA used BenMAP to estimate the health benefits directly attributable to reducing exposure to SO_2 to support a change in the NAAQS. Figure 5.2 below shows the major components of, and data inputs to, the BenMAP model.

Figure 5.2: Diagram of Inputs to BenMAP model for SO_2 Analysis



5.3.2 Air Quality Estimates

As Figure 5.2 shows, the primary input to any benefits assessment is the estimated changes in ambient air quality expected to result from a simulated control strategy or attainment of a particular standard. EPA typically relies upon air quality modeling to generate these data, but time and technical limitations described in Chapter 3 prevented us from generating new air quality modeling to simulate the changes in ambient SO_2 resulting from each control strategy. Instead, we utilize the ambient SO_2 concentrations modeled by CMAQ as part of the upcoming PM NAAQS RIA as our baseline.[3]

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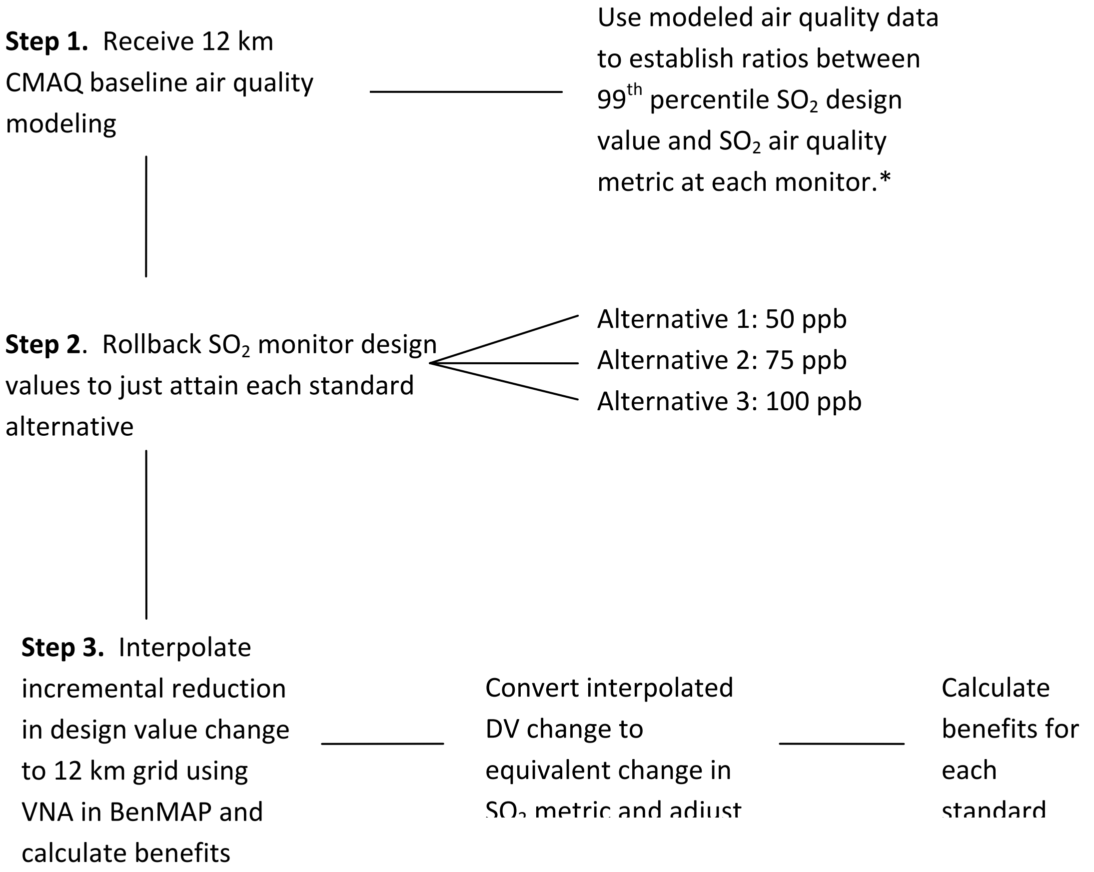
[3] See Chapter 3 for more detail regarding the air quality data used in this analysis.

The CMAQ air quality model provides projects both design values at SO_2 monitors and air quality concentrations at 12 km by 12 km grid cells nationwide. To estimate the benefits of fully attaining the standards in all areas, EPA employed the "monitor rollback" approach to approximate the air quality change resulting from just attaining alternative SO_2 NAAQS at each design value monitor. Figure 5.3 depicts the rollback process, which differs from the technique described in Chapter 3. The emission control strategy estimated the level of emission reductions necessary to attain each alternate NAAQS standard, whereas the approach described here aims to estimate the change in population exposure associated with attaining an alternate NAAQS. This approach relies on data from the existing SO_2 monitoring network and the inverse distance squared variant of the Veronoi Neighborhood Averaging (VNA) interpolation method to adjust the CMAQ-modeled SO_2 concentrations such that each area just attains the standard alternatives. We believe that the interpolation method using inverse distance squared most appropriately reflects the exposure gradient for SO_2 around each monitor (EPA, 2008c). A sensitivity analysis in Table 5.6 shows that the results are not particularly sensitive to the interpolation method.

Figure 5.3: Diagram of Rollback Method



*Metrics used in the epidemiology studies include the 24-hr mean, 3-hr mean, 8-hr max, and 1-hr max.

Because the VNA rollback approach interpolates monitor values, it is most reliable in areas with a denser monitoring network. In areas with a sparser monitoring network, there is less observed monitoring data to support the VNA interpolation and we have less confidence in the predicted air quality values further away from the monitors. For this reason, we interpolated air quality values—and estimated health impacts—within the CMAQ grid cells that are located within 50 km of the monitor, assuming that emission changes within this radius would affect the SO_2 concentration at each monitor. Limiting the interpolation to this radius attempts to account for the limitations of the VNA approach, the air quality data limitations identified in Chapter 3 and ensures that the benefits and costs analyses consider a consistent geographic area.[4] Therefore, the primary benefits analysis assesses health impacts occurring to populations living in the CMAQ grid cells located within the 50 km buffer for the specific geographic areas assumed to not attain the alternate standard levels. We test the sensitivity of this assumption relative to other exposure buffers in Table 5.6.

5.4 Estimating Avoided Health Effects from SO_2 Exposure

Following an extensive evaluation of health evidence from epidemiologic and laboratory studies, the U.S. EPA has concluded that there is a causal relationship between respiratory health effects and short-term exposure to SO_2 (U.S. EPA, 2008c). The immediate effect of SO_2 on the respiratory system in humans is bronchoconstriction. This response is mediated by chemosensitive receptors in the tracheobronchial tree, which trigger reflexes at the central nervous system level resulting in bronchoconstriction, mucus secretion, mucosal vasodilation, cough, and apnea followed by rapid shallow breathing. In some cases, local nervous system reflexes also may be involved. Asthmatics are more sensitive to the effects of SO_2 likely resulting from preexisting inflammation associated with this disease. This inflammation may lead to enhanced release of mediators, alterations in the autonomic nervous system and/or sensitization of the chemosensitive receptors. These biological processes are likely to underlie the bronchoconstriction and decreased lung function observed in response to SO_2 exposure. A clear concentration-response relationship has been demonstrated in laboratory studies following exposures to SO_2 at concentrations between 20 and 100 ppb, both in terms of increasing severity of effect and percentage of asthmatics adversely affected.

5.4.1 Selection of Health Endpoints for SO_2

Epidemiological researchers have associated SO_2 exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies, as described in the Integrated

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[4] Please see Chapter 3 for more information regarding the technical basis for the 50 km assumption.

Science Assessment for Oxides of Sulfur - Health Criteria (Final Report) (U.S. EPA, 2008c); hereafter, "SO_2 ISA"). The SO_2 ISA provides a comprehensive review of the current evidence of health and environmental effects of SO_2.

Previous reviews of the SO_2 primary NAAQS, most recently in 1996, did not include a quantitative benefits assessment for SO_2 exposure. As the first health benefits assessment for SO_2 exposure, we build on the methodology and lessons learned from the SO_2 risk and exposure assessment (U.S. EPA, 2009c) and the benefits assessments for the recent $PM_{2.5,}$ $O_{3,}$ and NO_2 NAAQS (U.S. EPA, 2006a; U.S. EPA, 2008a; U.S. EPA, 2010a; U.S. EPA, 2010b).

We quantified SO_2-related health endpoints for which the SO_2 ISA provides the strongest evidence of an effect. In general, we follow a weight of evidence approach, based on the biological plausibility of effects, availability of concentration-response functions from well conducted peer-reviewed epidemiological studies, cohesiveness of results across studies, and a focus on endpoints reflecting public health impacts (like hospital admissions) rather than physiological responses (such as changes in clinical measures like Forced Expiratory Volume (FEV1)). The differing evidence and associated strength of the evidence for these different effects is described in detail in the SO_2 ISA.

Although a number of adverse health effects have been found to be associated with SO_2 exposure, this benefits analysis only includes a subset due to limitations in understanding and quantifying the dose-response relationship for some of these health endpoints. In this analysis, we only estimated the benefits for those endpoints with sufficient evidence to support a quantified concentration-response relationship using the information presented in the SO_2 ISA, which contains an extensive literature review for several health endpoints related to SO_2 exposure. Because the ISA only included studies published or accepted for publication through April 2008, we also performed supplemental literature searches in the online search engine PubMed® to identify relevant studies published between January 2008, and the present.[5] Based on our review of this information, we quantified four short-term respiratory morbidity endpoints that the SO_2 ISA identified as a "causal relationship": acute respiratory symptoms, asthma exacerbation, respiratory-related emergency department visits, and respiratory-related hospitalizations.

Table 5.1 presents the health effects related to SO_2 exposure quantified in this benefits analysis. In addition, the table includes other endpoints potentially linked to SO_2 exposure, but which we are not yet ready to quantify with dose-response functions. For a list of the health

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[5] The O'Connor et al. study (2008) is the only study included in this analysis that was published after the cut-off date for inclusion in the SO2 ISA.

effects related to $PM_{2.5}$ exposure that we quantify in this analysis, please see Table 5.6 in section 5.7.

The SO_2 ISA concluded that the relationship between short-term SO_2 exposure and premature mortality was "suggestive of a causal relationship" because it is difficult to attribute the mortality risk effects to SO_2 alone. Therefore, we decided not to quantify premature mortality from SO_2 exposure in this analysis despite evidence suggesting a positive association (U.S. EPA, 2008c). Although the SO_2 ISA stated that studies are generally consistent in reporting a relationship between SO_2 exposure and mortality, there was a lack of robustness of the observed associations to adjustment for co-pollutants. As the literature continues to evolve, we may revisit this decision in future benefits assessment for SO_2.

As noted in Table 5.1, we are not able to quantify several welfare benefit categories in this analysis because we are limited by the available data or resources. Although we cannot quantify the ecosystem benefits of reducing sulfur deposition or visibility improvements in this analysis, we provide a qualitative analysis in section 5.9.

Table 5.1: Human Health and Welfare Effects of SO_2

Pollutant / Effect	Quantified and Monetized in Primary Estimates [a]	Unquantified Effects [b, c] Changes in:
SO_2 /Health	Respiratory Hospital Admissions	Premature mortality
	Asthma ER visits	Pulmonary function
	Asthma exacerbation	Other respiratory emergency department visits
	Acute Respiratory symptoms	Other respiratory hospital admissions
SO_2 /Welfare		Visibility improvements
		Commercial fishing and forestry from acidic deposition
		Recreation in terrestrial and aquatic ecosystems from acid deposition
		Increased mercury methylation

[a] Primary quantified and monetized effects are those included when determining the primary estimate of total monetized benefits of the alternative standards.

[b] The categorization of unquantified toxic health and welfare effects is not exhaustive.

[c] Health endpoints in the unquantified benefits column include both a) those for which there is not consensus on causality and those for which causality has been determined but empirical data are not available to allow calculation of benefits.

5.4.2 Selection of Concentration-Response Functions

After identifying the health endpoints to quantify in this analysis, we then selected concentration-response functions drawn from the epidemiological literature identified in the SO_2 ISA. We considered several factors, in the order below, in selecting the appropriate epidemiological studies and concentration-response functions for this benefits assessment.

1. We considered ambient SO_2 studies that were identified as key studies in the SO_2 ISA (or a more recent study), excluding those affected by the general additive model (GAM) S-Plus issue.[6]
2. We judged that studies conducted in the United States are preferable to those conducted outside the United States, given the potential for effect estimates to be affected by factors such as the ambient pollutant mix, the placement of monitors, activity patterns of the population, and characteristics of the healthcare system especially for hospital admissions and emergency department visits. We include Canadian studies in sensitivity analyses, when available.
3. We only incorporated concentration-response functions for which there was a corresponding valuation function. Currently, we only have a valuation function for asthma-related emergency department visits, but we do not have a valuation function for all-respiratory-related emergency department visits.
4. We preferred concentration-response functions that correspond to the age ranges most relevant to the specific health endpoint, with non-overlapping ICD-9 codes. We preferred completeness when selecting functions that correspond to particular age ranges and ICD codes. Age ranges and ICD codes associated with the selected functions are identified in Table 5.2.
5. We preferred multi-city studies or combined multiple single city studies, when available.
6. When available, we judged that effect estimates with distributed or cumulative lag structures were most appropriate for this analysis.
7. When available, we selected SO_2 concentration-response functions based on multi-pollutant models. Studies with multi-pollutant models are identified in Table 5.2.

These criteria reflect our preferences for study selection, and it was possible to satisfy many of these, but not all. There are trade-offs inherent in selecting among a range of studies, as not all studies met all criteria outlined above. At minimum, we ensured that none of the studies were GAM affected, we selected only U.S. based studies, and we quantified health endpoints for which there was a corresponding valuation function.

We believe that U.S.-based studies are most appropriate studies to use in this analysis to estimate the number of hospital admissions associated with SO_2 exposure because of the

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[6] The S-Plus statistical software is widely used for nonlinear regression analysis in time-series research of health effects. However, in 2002, a problem was discovered with the software's default conversion criteria in the general additive model (GAM), which resulted in biased relative risk estimates in many studies. This analysis does not include any studies that encountered this problem. For more information on this issue, please see U.S. EPA (2002).

characteristics of the ambient air, population, and healthcare system. Using only U.S.-based studies, we are limited to one epidemiology study for hospital admissions (Schwartz, 1996). However, there are several Canada-based epidemiology studies that also estimate respiratory hospital admissions (Fung, 2006; Luginaah, 2005; Yang, 2003). Table 5.12 provides the sensitivity of the SO_2 benefits using the effect estimates from the Canadian studies. Compared to the U.S. based study, the Canadian studies produce a substantially larger estimate of hospital admissions associated with SO_2 exposure.

When selecting concentration-response functions to use in this analysis, we reviewed the scientific evidence regarding the presence of thresholds in the concentration-response functions for SO_2 -related health effects to determine whether the function is approximately linear across the relevant concentration range. The SO_2 ISA concluded that, "The overall limited evidence from epidemiologic studies examining the concentration-response function of SO_2 health effects is inconclusive regarding the presence of an effect threshold at current ambient levels." For this reason, we have not incorporated thresholds in the concentration-response functions for SO_2 -related health effects in this analysis.

Table 5.2 shows the studies and health endpoints that we selected for this analysis. Table 5.3 shows the baseline health data used in combination with these health functions. Following these tables is a description of each of the epidemiology studies used in this analysis.

Table 5.2: SO_2 -Related Health Endpoints Quantified, Studies Used to Develop Health Impact Functions and Sub-Populations to which They Apply

Endpoint	Study	Study Population
Hospital Admissions		
All respiratory	Schwartz et al., 1996 – ICD-9 460-519	65 - 99
Emergency Department Visits		
Asthma	Pooled Estimate: Ito et al. (2007)—ICD-9 493 Michaud (2004) – ICD-9 493 NYDOH (2006)[b]—ICD-9 493 Peel et al. (2005)—ICD-9 493 Wilson (2005) – ICD-9 493	All ages
Other Health Endpoints		
Asthma exacerbations	Pooled estimate: Mortimer et al. (2002) (one or more symptoms)[a] O'Connor et al. (2008) (slow play, missed school days[c], nighttime asthma)[a, b] Schildcrout et al. (2006) (one or more symptoms)[a]	4 - 12
Acute Respiratory Symptoms	Schwartz et al. (1994)[b]	7 - 14

[a] The original study populations were 4 to 9 for the Mortimer et al. (2002) study and 5 to 12 for the O'Connor et al. (2008) study and the Schildcrout et al. (2006) study. We extended the applied population to facilitate the pooling process, recognizing the common biological basis for the effect in children in the broader age group. See: National Research Council (NRC). 2002. *Estimating the Public Health Benefits of Proposed Air Pollution Regulations*. Washington, DC: The National Academies Press, pg 117.

[b] Study specifies a multipollutant model.

[c] The form of this one function was not clear from the study. For this analysis, we assumed that it was log-linear, but we have subsequently determined that it is logistic. This adds a small amount to uncertainty regarding the asthmas incidence estimates, but this uncertainty is obscured by the rounding of the monetized estimates.

Table 5.3: National Average Baseline Incidence Rates used to Calculate SO_2 -Related Health Impacts [a]

Endpoint	Source	Notes	Rate per 100 people per year by Age Group						
			<18	18–24	25–34	35–44	45–54	55–64	65+
Respiratory Hospital Admissions	1999 NHDS public use data files [b]	incidence	0.043	0.084	0.206	0.678	1.926	4.389	11.629
Asthma ER visits	2000 NHAMCS public use data files [c]; 1999 NHDS public use data files [b]	incidence	1.011	1.087	0.751	0.438	0.352	0.425	0.232
Minor Restricted Activity Days (MRADs)	Schwartz (1994, table 2)	incidence	0.416	—	—	—	—	—	—
Asthma Exacerbations	Mortimer et al. (2002)	Incidence (and prevalence) among asthmatic children		Any morning symptom			0.116 (0.0567) [d]		
	O'Connor et al. (2008)	Incidence (and prevalence) among asthmatic children		Missed school One or more symptoms Slow play Nighttime asthma			0.057 (0.0567) [d] 0.207 (0.0567) [d] 0.157 (0.0567) [d] 0.121 (0.0567) [d]		
	Schildcrout et al. (2006)	Incidence (and prevalence) among asthmatic children		One or more symptoms			0.52 (0.0567) [d]		

[a] The following abbreviations are used to describe the national surveys conducted by the National Center for Health Statistics: HIS refers to the National Health Interview Survey; NHDS—National Hospital Discharge Survey; NHAMCS—National Hospital Ambulatory Medical Care Survey.

[b] See ftp://ftp.cdc.gov/pub/Health_Statistics/NCHS/Datasets/NHDS/

[c] See ftp://ftp.cdc.gov/pub/Health_Statistics/NCHS/Datasets/NHAMCS/

[d] We assume that this prevalence rate for ages 5 to 9 is also applicable down to age 4.

Schwartz et al. (1996)

Schwartz et al. (1996) is a review paper with an example drawn from hospital admissions of the elderly in Cleveland, Ohio from 1988-1990. The authors argued that the central issue is control for seasonality. They illustrated the use of categorical variables for weather and sinusoidal terms for filtering season in the Cleveland example. After controlling for season, weather, and day of the week effects, hospital admissions of persons aged 65 and older in Cleveland for respiratory illness was associated with ozone (RR = 1.09, 95% CI 1.02, 1.16) and PM_{10} (RR = 1.12, 95% CI 1.01, 1.24), and marginally associated with SO_2 (RR = 1.03, 95% CI = 0.99, 1.06). All of the relative risks are for a 100 micrograms/m^3 increase in the pollutant.

Fung et al. (2006) – Sensitivity Analysis

Fung et al. (2006) assessed the impact of ambient gaseous pollutants (SO_2, NO_2, CO, and O_3) and particulate matters (PM_{10}, $PM_{2.5}$, and $PM_{10\text{-}2.5}$) as well as the coefficient of haze (COH) on recurrent respiratory hospital admissions (ICD-9 codes 460-519) among the elderly in Vancouver, Canada, for the period of June 1, 1995, to March 31, 1999, using a new method proposed by Dewanji and Moolgavkar (2000; 2002). The authors found significant associations between respiratory hospital admissions and 3-day, 5-day, and 7-day moving averages of the ambient SO_2 concentrations, with the strongest association observed at the 7-day lag (RR = 1.044, 95% CI: 1.018-1.070). The authors also found $PM_{10\text{-}2.5}$ for 3-day and 5-day lag to be significant, with the strongest association at 5-day lag (RR = 1.020, 95% CI: 1.001-1.039). No significant associations with admission were found with current day exposure.

Luginaah et al. (2005) – Sensitivity analysis

Luginaah et al. (2005) assessed the association between air pollution and daily respiratory hospitalization (ICD-9 codes 460-519) for different age and sex groups from 1995 to 2000. The pollutants included were NO_2, SO_2, CO, O_3, PM_{10}, coefficient of haze (COH), and total reduced sulfur (TRS). The authors estimated relative risks (RR) using both time-series and case-crossover methods after controlling for appropriate confounders (temperature, humidity, and change in barometric pressure). The results of both analyses were consistent. They found associations between NO_2, SO_2, CO, COH, or PM_{10} and daily hospital admission of respiratory diseases especially among females. For females 0-14 years of age, there was 1-day delayed effect of NO_2 (RR = 1.19, case-crossover method), a current-day SO_2 (RR = 1.11, time series), and current-day and 1- and 2-day delayed effects for CO by case crossover (RR = 1.15, 1.19, 1.22, respectively). Time-series analysis showed that 1-day delayed effect of PM_{10} on respiratory admissions of adult males (15-64 years of age), with an RR of 1.18. COH had significant effects on female respiratory hospitalization, especially for 2-day delayed effects on adult females, with RRs of 1.15 and 1.29 using time-series and case-crossover analysis, respectively. There were no significant associations between O_3 and TRS with respiratory admissions.

Yang et al. (2003) – Sensitivity analysis

Yang et al. (2003) examined the impact of ozone, nitrogen dioxide, sulfur dioxide, carbon monoxide, and coefficient of haze on daily respiratory admissions (ICD-9 codes 460-519) in both young children (<3 years of age) and the elderly (65-99 years of age) in greater

Vancouver, British Columbia during the 13-yr period 1986-1998. Bidirectional case-crossover analysis was used to investigate associations and odds ratios were reported for single-pollutant, two-pollutant and multiple-pollutant models. Sulfur dioxide was found marginally significant in all models for elderly.

Ito et al. (2007)

Ito et al. (2007) assessed associations between air pollution and asthma emergency department visits in New York City for all ages. Specifically they examined the temporal relationships among air pollution and weather variables in the context of air pollution health effects models. The authors compiled daily data for $PM_{2.5}$, O_3, NO_2, SO_2, CO, temperature, dew point, relative humidity, wind speed, and barometric pressure for New York City for the years 1999-2002.The authors evaluated the relationship between the various pollutants' risk estimates and their respective concurvities, and discuss the limitations that the results imply about the interpretability of multi-pollutant health effects models.

Michaud et al. (2004)

Michaud et al. (2004) examined the association of emergency department (ED) visits in Hilo, Hawai'i, from January 1997 to May 2001 with volcanic fog, or "vog", measured as sulfur dioxide (SO_2) and submicrometer particulate matter (PM_1). Log-linear regression models were used with robust standard errors. The authors studied four diagnostic groups: asthma/COPD; cardiac; flu, cold, and pneumonia; and gastroenteritis. Before adjustments, highly significant associations with vog-related air quality were seen for all diagnostic groups except gastroenteritis. After adjusting for month, year, and day of the week, only asthma/COPD had consistently positive associations with air quality. They found that the strongest associations were for SO_2 with a 3-day lag (6.8% per 10 ppb; P=0.001) and PM_1, with a 1-day lag (13.8% per 10 $\mu g/m^3$; P=0.011).

NYDOH (2006)

New York State Department of Health (NYDOH) investigated whether day-to-day variations in air pollution were associated with asthma emergency department (ED) visits in Manhattan and Bronx, NYC and compared the magnitude of the air pollution effect between the two communities. NYDOH (2006) used Poisson regression to test for effects of 14 key air contaminants on daily ED visits, with control for temporal cycles, temperature, and day-of-week effects. The core analysis utilized the average exposure for the 0- to 4-day lags. Mean daily SO_2 was found significantly associated with asthma ED visits in Bronx but not Manhattan. Their findings of more significant air pollution effects in the Bronx are likely to relate in part to greater statistical power for identifying effects in the Bronx where baseline ED visits were greater, but they may also reflect greater sensitivity to air pollution effects in the Bronx.

Peel et al. (2005)

Peel et al. (2005) examined the associations between air pollution and respiratory emergency department visits (i.e., asthma (ICD-9 code 493, 786.09), COPD (491,492,496), URI (460-466, 477), pneumonia (480-486), and an all respiratory-disease group) in Atlanta, GA from 1 January 1993 to 31 August 2000. They used 3-Day Moving Average (Lags of 0, 1, and 2 Days) and unconstrained distributed lag (Lags of 0 to 13 Days) in the Poisson regression analyses. In single-pollutant models, positive associations persisted beyond 3 days for several outcomes, and over a week for asthma. The effects of NO_2, CO or PM_{10} on asthma ED visits were found significant but SO_2 or O_3 were not significantly associated with asthma ED visits.

Wilson et al. (2005)

Daily emergency room (ER) visits for all respiratory (ICD-9 codes 460-519) and asthma (ICD-9 code 493) were compared with daily SO_2, O_3, and weather variables over the period 1998-2000 in Portland, Maine and 1996-2000 in Manchester, New Hampshire. Seasonal variability was removed from all variables using nonparametric smoothed function (LOESS). Wilson et al.(2005) used generalized additive models to estimate the effect of elevated levels of pollutants on ER visits. Relative risks of pollutants were reported over their inter-quartile range (IQR, the 75th -25th percentile pollutant values). In Portland, an IQR increase in SO_2 was associated with a 5% (95% CI 2-7%) increase in all respiratory ER visits and a 6% (95% CI 1-12%) increase in asthma visits. An IQR increase in O_3 was associated with a 5% (95% CI 1-10%) increase in Portland asthmatic ER visits. No significant associations were found in Manchester, New Hampshire, possibly due to statistical limitations of analyzing a smaller population. The absence of statistical evidence for a relationship should not be used as evidence of no relationship. This analysis reveals that, on a daily basis, elevated SO_2 and O_3 have a significant impact on public health in Portland, Maine.

Villeneuve et al. (2007) – Sensitivity Analysis

Villeneuve et al. (2007) examined the associations between air pollution and emergency department (ED) visits for asthma among individuals two years of age and older in the census metropolitan area of Edmonton, Canada between April 1, 1992 and March 31, 2002 using a time stratified case-crossover design. Daily air pollution levels for the entire region were estimated from three fixed-site monitoring stations. Odds ratios and their corresponding 95% confidence intervals were estimated using conditional logistic regression with adjustment for temperature, relative humidity and seasonal epidemic of viral related respiratory disease. Villeneuve et al.(2007) found positive associations for asthma ED visits with outdoor air pollution levels between April and September, but such associations were absent during the remainder of the year. Effects were strongest among young children (2-4 years of age) and elderly (>75 years of age). Air pollution risk estimates were largely unchanged after adjustment for aeroallergen levels. This study is not included in the SO_2 ISA only because it was published after the cut-off date, but it met all of the other criteria for inclusion in this analysis.

Mortimer et al. (2002)

Mortimer et al. (2002) examined the effect of daily ambient air pollution within a cohort of 846 asthmatic children residing in eight urban areas of the USA between June 1 to August 31, 1993, using data from the National Cooperative Inner-City Asthma Study. Daily air pollution concentrations were extracted from the Aerometric Information Retrieval System database from the Environment Protection Agency in the USA. Logistic models were used to evaluate the effects of several air pollutants (O_3, NO_2, SO_2 and PM_{10}) on peak expiratory flow rate (PEFR) and symptoms in 846 children (ages 4-9 yrs) with a history of asthma. In single pollutant models, each pollutant was associated with an increased incidence of morning symptoms: (odds ratio (OR) = 1.16 (95% CI 1.02-1.30) per IQR increase in 4-day average O_3, OR = 1.32 (95% CI 1.03-1.70) per IQR increase in 2-day average SO_2, OR = 1.48 (95% CI 1.02-2.16) per IQR increase in 6-day average NO_2 and OR = 1.26 (95% CI 1.0-1.59) per IQR increase in 2-day average PM_{10}. This longitudinal analysis supports previous time-series findings that at levels below current USA air-quality standards, summer-air pollution is significantly related to symptoms and decreased pulmonary function among children with asthma.

O'Connor et al. (2008)

O'Connor et al. (2008) investigated the association between fluctuations in outdoor air pollution and asthma exacerbation (wheeze-cough, nighttime asthma, slow play and school absence) among 861 inner-city children (5-12 years of age) with asthma in seven US urban communities. Asthma symptom data were collected every 2 months during the 2-year study period. Daily pollution measurements were obtained from the Aerometric Information Retrieval System between August 1998 and July 2001. The relationship of symptoms to fluctuations in pollutant concentrations was examined by using logistic models. In single-pollutant models, significant or nearly significant positive associations were observed between higher NO_2 concentrations and each of the health outcomes. The O_3, $PM_{2.5}$, and SO_2

concentrations did not appear significantly associated with symptoms or school absence except for a significant association between $PM_{2.5}$ and school absence. This study is not included in the SO_2 ISA only because it was published after the cut-off date, but it met all of the other criteria for inclusion in this analysis.

Schildcrout et al. (2006)

Schildcrout et al. (2006) investigated the relation between ambient concentrations of the five criteria pollutants (PM_{10}, O_3, NO_2, SO_2, and CO) and asthma exacerbations (daily symptoms and use of rescue inhalers) among 990 children in eight North American cities during the 22-month prerandomization phase (November 1993-September 1995) of the Childhood Asthma Management Program. Short-term effects of CO, NO_2, PM_{10}, SO_2, and warm-season O_3 were examined in both one-pollutant and two-pollutant models, using lags of up to 2 days in logistic and Poisson regressions. Lags in CO and NO_2 were positively associated with both measures of asthma exacerbation, and the 3-day moving sum of SO_2 levels was marginally related to asthma symptoms. PM_{10} and O_3 were unrelated to exacerbations. The strongest effects tended to be seen with 2-day lags, where a 1-parts-per-million change in CO and a 20-parts-per-billion change in NO_2 were associated with symptom odds ratios of 1.08 (95% confidence interval (CI): 1.02, 1.15) and 1.09 (95% CI: 1.03, 1.15), respectively.

Schwartz et al. (1994)

Schwartz et al. (1994) studied the association between ambient air pollution exposures and respiratory illness among 1,844 school children (7-14 years of age) in six U.S. cities during five warm season months between April and August. Daily measurements of ambient sulfur dioxide (SO_2), nitrogen dioxide (NO_2), ozone (O_3), inhalable particles (PM_{10}), respirable particles ($PM_{2.5}$), light scattering, and sulfate particles were made, along with integrated 24-h measures of aerosol strong acidity. Significant associations in single pollutant models were found between SO_2, NO_2, or $PM_{2.5}$ and incidence of cough, and between sulfur dioxide and incidence of lower respiratory symptoms. Significant associations were also found between incidence of coughing symptoms and incidence of lower respiratory symptoms and PM_{10}, and a marginally significant association between upper respiratory symptoms and PM_{10}.

Delfino et al. (2003) – Sensitivity Analysis

Delfino et al. (2003) conducted a panel study of 22 Hispanic children with asthma who were 10-16 years old and living in a Los Angeles community with high traffic density. Subjects filled out symptom diaries daily for up to 3 months (November 1999 through January 2000). Pollutants included ambient hourly values of ozone (O_3), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and carbon monoxide (CO) and 24-hr values of volatile organic compounds (VOCs), particulate matter with aerodynamic diameter < 10 micro (PM_{10}), and elemental carbon (EC) and organic carbon (OC) PM_{10} fractions. Asthma symptom severity was regressed on pollutants using logistic models. The authors found positive associations of symptoms with criteria air pollutants (O_3, NO_2, SO_2, and PM_{10}). Selected adjusted odds ratio for more severe asthma symptoms from interquartile range increases in pollutants was, for 2.5 ppb 8-hr max SO_2, 1.36 [95% confidence interval (CI), 1.08-1.71]. Their findings support the view that air toxins in the pollutant mix from traffic and industrial sources may have adverse effects on asthma in children.

5.4.3 Pooling Multiple Health Studies

After selecting which health endpoints to analyze and which epidemiology studies provide appropriate effect estimates, we then selected a method to combine the multiple health studies to provide a single benefits estimate for each health endpoint. The purpose of pooling multiple studies together is to generate a more robust estimate by combining the evidence across multiple studies and cities. Because we used a single study for acute respiratory symptoms and a single study for hospital admission for asthma, there was no pooling necessary for those endpoints.

See Table 5.2 for more information on how the asthma studies were adjusted. Because asthma represents the largest benefits category in this analysis, we tested the sensitivity of the SO_2 benefits to alternate pooling choices in Table 5.6.

5.5 Valuation of Avoided Health Effects from SO_2 Exposure

The selection of valuation functions very similar to the NO_2 NAAQS RIA (U.S. EPA, 2010b) and the $PM_{2.5}$ NAAQS RIA (U.S. EPA, 2006a) with a couple exceptions. First, in this analysis, we estimated changes in all respiratory hospital admissions. This is consistent with the $PM_{2.5}$ NAAQS RIA, but inconsistent with the NO_2 NAAQS RIA, which estimated changes for only a subset of respiratory hospital admissions (i.e., chronic lung disease and asthma) because concentration-response functions were only available for the subset. Second, in this analysis, we used the any-of-19 symptoms valuation function for acute respiratory symptoms. This is consistent with the NO_2 NAAQS RIA, but inconsistent with the $PM_{2.5}$ NAAQS RIA, which used the valuation function for “minor-restricted activity day” (MRADs). The valuation for any-of-19-symptoms is approximately 50% of the valuation for MRADs. Consistent with economic theory, these valuation functions include adjustments for inflation (2006$) and income growth over time (2020 income levels). Table 5.4 provides the unit values used to monetize the benefits of reduced exposure to SO_2.

Table 5.4: Central Unit Values SO_2 Health Endpoints (2006$)*

Health Endpoint	Central Unit Value Per Statistical Incidence (2020 income level)	Derivation of Distributions of Estimates
Hospital Admissions and ER Visits		
Respiratory Hospital Admissions	$24,000	No distributional information available. The COI point estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total COPD category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).
Asthma Emergency Room Visits	$370	No distributional information available. Simple average of two unit COI values: (1) $400 (2006$), from Smith et al. (1997) and (2) $340 (2006$), from Stanford et al. (1999).
Respiratory Ailments Not Requiring Hospitalization		
Asthma Exacerbation	$53	Asthma exacerbations are valued at $49 (2006$) per incidence, based on the mean of average WTP estimates for the four severity definitions of a “bad asthma day,” described in Rowe and Chestnut (1986). This study surveyed asthmatics to estimate WTP for avoidance of a “bad asthma day,” as defined by the subjects. For purposes of valuation, an asthma exacerbation is assumed to be equivalent to a day in which asthma is moderate or worse as reported in the Rowe and Chestnut (1986) study. The value is assumed have a uniform distribution between $19 and $83 (2006$).
Acute Respiratory Symptoms	$30	The valuation estimate for "any of 19 acute respiratory symptoms” is derived from Krupnick et al. (1990) assuming that this health endpoint consists either of upper respiratory symptoms (URS) or lower respiratory symptoms (LRS), or both. We assumed the following probabilities for a day of "any of 19 acute respiratory symptoms": URS with 40 percent probability, LRS with 40 percent probability, and both with 20 percent probability. The point estimate of WTP to avoid a day of “the presence of any of 19 acute respiratory symptoms” is $28 (2006$). The value is assumed have a uniform distribution between $0 and $56 (2006$).

*All estimates rounded to two significant figures. All values have been inflated to reflect values in 2006 dollars and income levels in 2020.

5.6 Health Benefits of Reducing Exposure to SO_2 Results

EPA estimated the monetized human health benefits of reducing cases of morbidity among populations exposed to SO_2 in 2020 for the selected standard and the alternative standard levels in 2006$. For the selected SO_2 standard at 75 ppb, the monetized benefits from reduced SO_2 exposure would be $2.2 million in 2020. Figure 5.4 shows the breakdown of the monetized SO_2 benefits by health endpoint. Table 5.5 shows the incidences of health effects and monetized benefits of attaining the alternative standard levels by health endpoint. Because all health effects from SO_2 exposure are expected to occur within the analysis year, the monetized benefits for SO_2 do not need to be discounted. Please note that these benefits do not include any of the benefits listed as "unquantified" in Table 5.1, nor do they include the PM co-benefits, which are presented in the section 5.7.

Figure 5.4: Breakdown of Monetized SO_2 Health Benefits by Endpoint

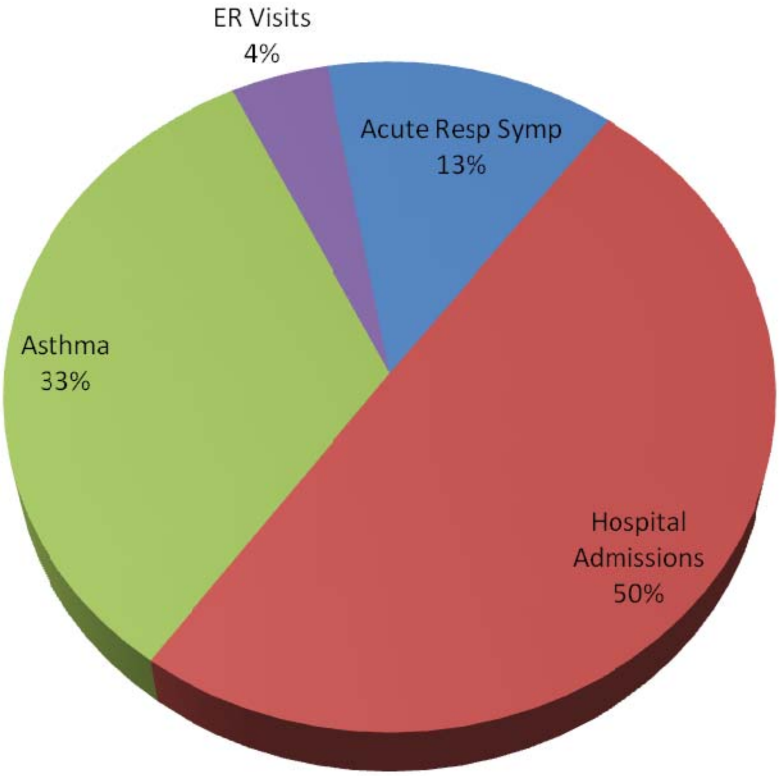

Table 5.5: SO_2 Health Benefits of Attaining Alternate Standard Levels in 2020 in 2006$ (95th percentile confidence interval)

		Incidence		Valuation	
50 ppb	Acute Respiratory Symptoms	38,000	(-21,000 -- 97,000)	$1,100,000	(-$730,000 -- $4,200,000)
	Hospital Admissions, Respiratory	170	(-10 -- 360)	$4,100,000	($120,000 -- $8,100,000)
	Asthma Exacerbation	55,000	(7,800 -- 130,000)	$2,900,000	($440,000 -- $8,800,000)
	Emergency Room Visits, Respiratory	930	(-230 -- 2,600)	$340,000	(-$53,000 -- $940,000)
			Total	**$8,500,000**	**(-$210,000 -- $22,000,000)**
75 ppb	Acute Respiratory Symptoms	9,400	(-5,200 -- 24,000)	$280,000	(-$180,000 -- $1,100,000)
	Hospital Admissions, Respiratory	46	(-3 -- 95)	$1,100,000	($33,000 -- $2,100,000)
	Asthma Exacerbation	14,000	(1,900 -- 33,000)	$720,000	($110,000 -- $2,200,000)
	Emergency Room Visits, Respiratory	260	(-65 -- 720)	$95,000	(-$15,000 -- $260,000)
			Total	**$2,200,000**	**(-$52,000 -- $5,600,000)**
100 ppb	Acute Respiratory Symptoms	2,600	(-1,500 -- 6,700)	$80,000	(-$50,000 -- $290,000)
	Hospital Admissions, Respiratory	13	(-1 -- 27)	$310,000	($9,500 -- $620,000)
	Asthma Exacerbation	3,800	(530 -- 9,200)	$200,000	($30,000 -- $610,000)
	Emergency Room Visits, Respiratory	74	(-19 -- 200)	$27,000	(-$4,400 -- $74,000)
			Total	**$620,000**	**(-$15,000 -- $1,600,000)**

*All estimates are rounded to two significant figures. The negative 5th percentile incidence estimates for acute respiratory symptoms are a result of the weak statistical power of the study and should not be inferred to indicate that decreased SO_2 exposure may cause an increase in this health endpoint.

In Table 5.6, we present the results of sensitivity analyses for the SO_2 benefits. We indicate each input parameter, the value used as the default, and the values for the sensitivity analyses, and then we provide the total monetary benefits for each input and the percent change from the default value.

Table 5.6: Sensitivity Analyses for SO_2 Health Benefits to Fully Attain 50 ppb Standard

		Total SO_2 Benefits (millions of 2006$)	**% Change from Default**
Exposure Estimation Method	50km radius	$2.2	N/A
	75km radius	$2.7	25%
	100km radius	$3.1	42%
	150km radius	$3.7	71%
Location of Hospital Admission Studies	w/US-based studies only	$2.2	N/A
	w/Canada-based studies only	$12	438%
Asthma Pooling Method	Pool all endpoints together	$2.2	N/A
	One or more symptoms only	$2.2	-0.2%
Interpolation Method	Inverse distance squared	$2.2	N/A
	Inverse distance	$2.5	12%

5.7 $PM_{2.5}$ Co-Benefits

Because SO_2 is also a precursor to $PM_{2.5,}$ reducing SO_2 emissions in the projected non-attainment areas will also reduce $PM_{2.5}$ formation, human exposure and the incidence of $PM_{2.5}$-related health effects. In this analysis, we estimated the co-benefits of reducing $PM_{2.5}$ exposure for the alternative standards. Due to analytical limitations, it was not possible to provide a comprehensive estimate of $PM_{2.5}$-related benefits. Instead, we used the "benefit-per-ton" method to estimate these benefits (Fann et al, 2009). Please see Chapter 4 for more information on the tons of emission reductions calculated for the control strategy.[7]

The $PM_{2.5}$ benefit-per-ton methodology incorporates key assumptions described in detail below. These $PM_{2.5}$ benefit-per-ton estimates provide the total monetized human health benefits (the sum of premature mortality and premature morbidity) of reducing one ton of $PM_{2.5}$ from a specified source. EPA has used the benefit per-ton technique in previous RIAs, including the recent Ozone NAAQS RIA (U.S. EPA, 2010a) and NO_2 NAAQS RIA (U.S. EPA, 2010b). Table 5.7 shows the quantified and unquantified benefits captured in those benefit-per-ton estimates.

Table 5.7: Human Health and Welfare Effects of $PM_{2.5}$

Pollutant / Effect	Quantified and Monetized in Primary Estimates	Unquantified Effects Changes in:
$PM_{2.5}$	Adult premature mortality Bronchitis: chronic and acute Hospital admissions: respiratory and cardiovascular Emergency room visits for asthma Nonfatal heart attacks (myocardial infarction) Lower and upper respiratory illness Minor restricted-activity days Work loss days Asthma exacerbations (asthmatic population) Infant mortality	Subchronic bronchitis cases Low birth weight Pulmonary function Chronic respiratory diseases other than chronic bronchitis Non-asthma respiratory emergency room visits Visibility Household soiling

Consistent with the Portland Cement NESHAP, the benefits estimates utilize the concentration-response functions as reported in the epidemiology literature, as well as the 12 functions obtained in EPA's expert elicitation study as a sensitivity analysis.

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[7] Pollution controls installed to comply with this standard would also reduce ambient $PM_{2.5}$ concentrations. This illustrative analysis is incremental to the 2006 PM NAAQS, so these benefits are in addition to those estimates for that rule. Furthermore, the controls installed to comply with this standard might also help states attain a more stringent PM NAAQS if one is promulgated in 2011.

- One estimate is based on the concentration-response (C-R) function developed from the extended analysis of American Cancer Society (ACS) cohort, as reported in Pope et al. (2002), a study that EPA has previously used to generate its primary benefits estimate. When calculating the estimate, EPA applied the effect coefficient as reported in the study without an adjustment for assumed concentration threshold of 10 µg/m^3 as was done in recent (2006-2009) Office of Air and Radiation RIAs.
- One estimate is based on the C-R function developed from the extended analysis of the Harvard Six Cities cohort, as reported by Laden et al. (2006). This study, published after the completion of the Staff Paper for the 2006 $PM_{2.5}$ NAAQS, has been used as an alternative estimate in the $PM_{2.5}$ NAAQS RIA and $PM_{2.5}$ co-benefits estimates in RIAs completed since the $PM_{2.5}$ NAAQS. When calculating the estimate, EPA applied the effect coefficient as reported in the study without an adjustment for assumed concentration threshold of 10 µg/m^3 as was done in recent (2006-2009) RIAs.
- Twelve estimates are based on the C-R functions from EPA's expert elicitation study (IEc, 2006; Roman et al., 2008) on the $PM_{2.5}$ -mortality relationship and interpreted for benefits analysis in EPA's final RIA for the $PM_{2.5}$ NAAQS. For that study, twelve experts (labeled A through L) provided independent estimates of the $PM_{2.5}$ -mortality concentration-response function. EPA practice has been to develop independent estimates of $PM_{2.5}$ -mortality estimates corresponding to the concentration-response function provided by each of the twelve experts, to better characterize the degree of variability in the expert responses.

The effect coefficients are drawn from epidemiology studies examining two large population cohorts: the American Cancer Society cohort (Pope et al., 2002) and the Harvard Six Cities cohort (Laden et al., 2006).[8] These are logical choices for anchor points in our presentation because, while both studies are well designed and peer reviewed, there are strengths and weaknesses inherent in each, which we believe argues for using both studies to generate benefits estimates. Previously, EPA had calculated benefits based on these two empirical studies, but derived the range of benefits, including the minimum and maximum results, from an expert elicitation of the relationship between exposure to $PM_{2.5}$ and premature mortality (Roman et al., 2008). Within this assessment, we include the benefits estimates derived from the concentration-response function provided by each of the twelve experts to better characterize the uncertainty in the concentration-response function for mortality and the degree of variability in the expert responses. Because the experts used these cohort studies to inform their concentration-response functions, benefits estimates using these functions generally fall between results using these epidemiology studies (see Figure 5.1). In

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[8] These two studies specify multi-pollutant models that control for SO_2, among other co-pollutants.

general, the expert elicitation results support the conclusion that the benefits of $PM_{2.5}$ control are very likely to be substantial.

Readers interested in reviewing the general methodology for creating the benefit-per-ton estimates used in this analysis should consult Fann et al. (2009) or the Technical Support Document (TSD) accompanying the ozone NAAQS RIA (USEPA 2008a). As described in the documentation for the benefit per-ton estimates cited above, national per-ton estimates are developed for selected pollutant/source category combinations. The per-ton values calculated therefore apply only to tons reduced from those specific pollutant/source combinations (e.g., SO_2 emitted from electric generating units; SO_2 emitted from area sources). Our estimate of $PM_{2.5}$ co-control benefits is therefore based on the total $PM_{2.5}$ emissions controlled by sector and multiplied by this per-ton value.

The benefit-per-ton coefficients in this analysis were derived using modified versions of the health impact functions used in the PM NAAQS Regulatory Impact Analysis. Specifically, this analysis uses the benefit-per-ton estimates first applied in the Portland Cement NESHAP RIA (U.S. EPA, 2009a), which incorporated three updates: a new population dataset, an expanded geographic scope of the benefit-per-ton calculation, and the functions directly from the epidemiology studies without an adjustment for an assumed threshold.[9] Removing the threshold assumption is a key difference between the method used in this analysis of PM-co benefits and the methods used in RIAs prior to Portland Cement, and we now calculate incremental benefits down to the lowest modeled $PM_{2.5}$ air quality levels.

EPA strives to use the best available science to support our benefits analyses, and we recognize that interpretation of the science regarding air pollution and health is dynamic and evolving. Based on our review of the body of scientific literature, EPA applied the no-threshold model in this analysis. EPA's final Integrated Science Assessment (2009d), which was recently reviewed by EPA’s Clean Air Scientific Advisory Committee (U.S. EPA-SAB, 2009a; U.S. EPA-SAB, 2009b), concluded that the scientific literature consistently finds that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship while recognizing potential uncertainty about the exact shape of the concentration-response function. In Table 5-12, we include an estimate of the sensitivity of the results to an assumed threshold at 10 $\mu g/m^3$.

As is the nature of Regulatory Impact Analyses (RIAs), the assumptions and methods used to estimate air quality benefits evolve over time to reflect the Agency’s most current

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[9] The benefit-per-ton estimates have also been updated since the Cement RIA to incorporate a revised VSL, as discussed on the next page.

interpretation of the scientific and economic literature. For a period of time (2004-2008), the Office of Air and Radiation (OAR) valued mortality risk reductions using a value of statistical life (VSL) estimate derived from a limited analysis of some of the available studies. OAR arrived at a VSL using a range of $1 million to $10 million (2000$) consistent with two meta-analyses of the wage-risk literature. The $1 million value represented the lower end of the interquartile range from the Mrozek and Taylor (2002) meta-analysis of 33 studies. The $10 million value represented the upper end of the interquartile range from the Viscusi and Aldy (2003) meta-analysis of 43 studies. The mean estimate of $5.5 million (2000$)[10] was also consistent with the mean VSL of $5.4 million estimated in the Kochi et al. (2006) meta-analysis. However, the Agency neither changed its official guidance on the use of VSL in rule-makings nor subjected the interim estimate to a scientific peer-review process through the Science Advisory Board (SAB) or other peer-review group.

During this time, the Agency continued work to update its guidance on valuing mortality risk reductions, including commissioning a report from meta-analytic experts to evaluate methodological questions raised by EPA and the SAB on combining estimates from the various data sources. In addition, the Agency consulted several times with the Science Advisory Board Environmental Economics Advisory Committee (SAB-EEAC) on the issue. With input from the meta-analytic experts, the SAB-EEAC advised the Agency to update its guidance using specific, appropriate meta-analytic techniques to combine estimates from unique data sources and different studies, including those using different methodologies (i.e., wage-risk and stated preference) (U.S. EPA-SAB, 2007).

Until updated guidance is available, the Agency determined that a single, peer-reviewed estimate applied consistently best reflects the SAB-EEAC advice it has received. Therefore, the Agency has decided to apply the VSL that was vetted and endorsed by the SAB in the Guidelines for Preparing Economic Analyses (U.S. EPA, 2000)[11] while the Agency continues its efforts to update its guidance on this issue. This approach calculates a mean value across VSL estimates derived from 26 labor market and contingent valuation studies published between 1974 and 1991. The mean VSL across these studies is $6.3 million (2000$).[12] The Agency is committed to using scientifically sound, appropriately reviewed evidence in valuing mortality risk reductions

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[10] After adjusting the VSL to account for a different currency year (2006$) and to account for income growth to 2020, the $5.5 million VSL is $7.7m.

[11] In the (draft) update of the Economic Guidelines (U.S. EPA, 2008d), EPA retained the VSL endorsed by the SAB with the understanding that further updates to the mortality risk valuation guidance would be forthcoming in the near future. Therefore, this report does not represent final agency policy.

[12] In this analysis, we adjust the VSL to account for a different currency year (2006$) and to account for income growth to 2020. After applying these adjustments to the $6.3 million value, the VSL is $8.9m.

and has made significant progress in responding to the SAB-EEAC's specific recommendations. The Agency anticipates presenting results from this effort to the SAB-EEAC in Spring 2010 and that draft guidance will be available shortly thereafter.

Table 5.8 provides the unit values used to monetize the benefits of reduced exposure to $PM_{2.5}$. Figure 5.5 illustrates the relative breakdown of the monetized $PM_{2.5}$ health benefits.

Table 5.8: Unit Values used for Economic Valuation of $PM_{2.5}$ Health Endpoints (2006$)*

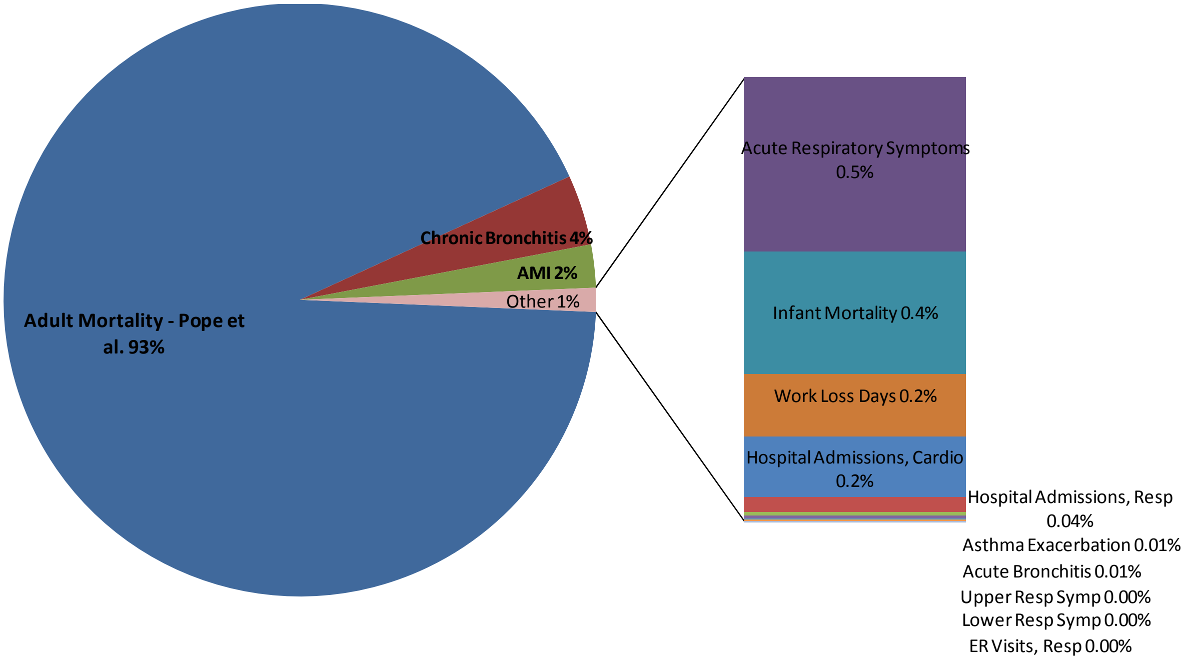
Health Endpoint	Central Estimate of Value Per Statistical Incidence (2020 income level)	Derivation of Distributions of Estimates
Premature Mortality (Value of a Statistical Life)	\$8,900,000	EPA currently recommends a central VSL of \$6.3m (2000\$) based on a Weibull distribution fitted to 26 published VSL estimates (5 contingent valuation and 21 labor market studies). The underlying studies, the distribution parameters, and other useful information are available in Appendix B of EPA's current Guidelines for Preparing Economic Analyses (U.S. EPA, 2000).
Chronic Bronchitis (CB)	\$490,000	The WTP to avoid a case of pollution-related CB is calculated as $WTP_x = WTP_{13} * e^{-\beta*(13-x)}$, where x is the severity of an average CB case, WTP13 is the WTP for a severe case of CB, and \$ is the parameter relating WTP to severity, based on the regression results reported in Krupnick and Cropper (1992). The distribution of WTP for an average severity-level case of CB was generated by Monte Carlo methods, drawing from each of three distributions: (1) WTP to avoid a severe case of CB is assigned a 1/9 probability of being each of the first nine deciles of the distribution of WTP responses in Viscusi et al. (1991); 2) the severity of a pollution-related case of CB (relative to the case described in the Viscusi study) is assumed to have a triangular distribution, with the most likely value at severity level 6.5 and endpoints at 1.0 and 12.0; and (3) the constant in the elasticity of WTP with respect to severity is normally distributed with mean = 0.18 and standard deviation = 0.0669 (from Krupnick and Cropper [1992]). This process and the rationale for choosing it is described in detail in the Costs and Benefits of the Clean Air Act, 1990 to 2010 (U.S. EPA, 1999b).
Nonfatal Myocardial Infarction (heart attack)		No distributional information available. Age-specific cost-of-illness values reflect lost earnings and direct medical costs over a 5-year on period following a nonfatal MI. Lost earnings estimates are based Cropper and Krupnick (1990). Direct medical costs are based on simple average of estimates from Russell et al. (1998) and Wittels et al. (1990). Lost earnings: Cropper and Krupnick (1990). Present discounted value of 5 years of lost earnings in (2006\$): age of onset: at 3%, at 7% 25–44: \$11,000, \$10,000 45–54: \$17,000, \$15,000 55–65: \$96,000, \$86,000
<u>3% discount rate</u>		
Age 0–24	\$80,000	
Age 25–44	\$96,000	
Age 45–54	\$100,000	
Age 55–65	\$180,000	
Age 66 and over	\$80,000	

7% discount rate		Direct medical expenses: An average of: 1. Wittels et al. (1990) ($130,000—no discounting) 2. Russell et al. (1998), 5-year period ($29,000 at 3%, $27,000 at 7%)
Age 0–24	$80,000	
Age 25–44	$88,000	
Age 45–54	$92,000	
Age 55–65	$160,000	
Age 66 and over	$78,000	
Hospital Admissions and ER Visits		
Chronic Obstructive Pulmonary Disease (COPD)	$17,000	No distributional information available. The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code-level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total COPD category illnesses) reported in Agency for Healthcare Research and Quality (2000) (www.ahrq.gov).
Asthma Admissions	$8,900	No distributional information available. The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code-level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total asthma category illnesses) reported in Agency for Healthcare Research and Quality (2000) (www.ahrq.gov).
All Cardiovascular	$25,000	No distributional information available. The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code-level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total cardiovascular category illnesses) reported in Agency for Healthcare Research and Quality (2000) (www.ahrq.gov).
All respiratory (ages 65+)	$25,000	No distributions available. The COI point estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total COPD category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).
All respiratory (ages 0–2)	$10,000	No distributions available. The COI point estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total COPD category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).
Emergency Room Visits for Asthma	$370	No distributional information available. Simple average of two unit COI values: (1) $400 (2006$), from Smith et al. (1997) and (2) $340 (2006$), from Stanford et al. (1999).
Respiratory Ailments Not Requiring Hospitalization		

Upper Respiratory Symptoms (URS)	$31	Combinations of the three symptoms for which WTP estimates are available that closely match those listed by Pope et al. result in seven different “symptom clusters,” each describing a “type” of URS. A dollar value was derived for each type of URS, using mid-range estimates of WTP (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. In the absence of information surrounding the frequency with which each of the seven types of URS occurs within the URS symptom complex, we assumed a uniform distribution between $11 and $50 (2006$).
Lower Respiratory Symptoms (LRS)	$19	Combinations of the four symptoms for which WTP estimates are available that closely match those listed by Schwartz et al. result in 11 different “symptom clusters,” each describing a “type” of LRS. A dollar value was derived for each type of LRS, using mid-range estimates of WTP (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. The dollar value for LRS is the average of the dollar values for the 11 different types of LRS. In the absence of information surrounding the frequency with which each of the 11 types of LRS occurs within the LRS symptom complex, we assumed a uniform distribution between $8 and $29 (2006$).
Asthma Exacerbations	$53	Asthma exacerbations are valued at $49 (2006$) per incidence, based on the mean of average WTP estimates for the four severity definitions of a “bad asthma day,” described in Rowe and Chestnut (1986). This study surveyed asthmatics to estimate WTP for avoidance of a “bad asthma day,” as defined by the subjects. For purposes of valuation, an asthma exacerbation is assumed to be equivalent to a day in which asthma is moderate or worse as reported in the Rowe and Chestnut (1986) study. The value is assumed have a uniform distribution between $19 and $83 (2006$).
Acute Bronchitis	$440	Assumes a 6-day episode, with the distribution of the daily value specified as uniform with the low and high values based on those recommended for related respiratory symptoms in Neumann et al. (1994). The low daily estimate of $12 (2006$) is the sum of the mid-range values recommended by IEc for two symptoms believed to be associated with acute bronchitis: coughing and chest tightness. The high daily estimate was taken to be twice the value of a minor respiratory restricted-activity day, or $130 (2006$).
Work Loss Days (WLDs)	Variable	No distribution available. Point estimate is based on county-specific median annual wages divided by 50 (assuming 2 weeks of vacation) and then by 5—to get median daily wage. U.S. Year 2000 Census, compiled by Geolytics, Inc.
Minor Restricted Activity Days (MRADs)	$63	Median WTP estimate to avoid one MRAD from Tolley et al. (1986). Distribution is assumed to be triangular with a minimum of $26 and a maximum of $97 (2006$). Range is based on assumption that value should exceed WTP for a single mild symptom (the highest estimate for a single symptom—for eye irritation—is $19 (2006$)) and be less than that for a WLD. The triangular distribution acknowledges that the actual value is likely to be closer to the point estimate than either extreme.

*All estimates rounded to two significant figures. All values have been inflated to reflect values in 2006 dollars.

Figure 5.5: Breakdown of Monetized $PM_{2.5}$ Health Benefits using Mortality Function from Pope et al.*



*This pie chart is an illustrative breakdown of the monetized PM co-benefits, using the results based on Pope et al. (2002) as an example. Using the Laden et al. (2006) function for premature mortality, the percentage of total monetized benefits due to adult mortality would be 97%. This chart shows the breakdown using a 3% discount rate, and the results would be similar if a 7% discount rate was used.

Because epidemiology studies have indicated that there is a lag between exposure to $PM_{2.5}$ and premature mortality, the discount rate has a substantial effect on the final monetized benefits.[13] We provide the PM co-benefit results using discount rates of 3% and 7% in Table 5.11 and the total monetized benefits (i.e., SO_2 and $PM_{2.5}$) results using both discount rates in Table 5.13. We test the sensitivity of the PM results to discount rates of 3% and 7% in Table 5.12.

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[13] To comply with Circular A-4, EPA provides monetized benefits using discount rates of 3% and 7% (OMB, 2003). These benefits are estimated for a specific analysis year (i.e., 2020), and most of the PM benefits occur within that year with two exceptions: acute myocardial infarctions (AMIs) and premature mortality. For AMIs, we assume 5 years of follow-up medical costs and lost wages. For premature mortality, we assume that there is a "cessation" lag between PM exposures and the total realization of changes in health effects. Although the structure of the lag is uncertain, EPA follows the advice of the SAB-HES to assume a segmented lag structure characterized by 30% of mortality reductions in the first year, 50% over years 2 to 5, and 20% over the years 6 to 20 after the reduction in $PM_{2.5}$ (U.S. EPA-SAB, 2004). Changes in the lag assumptions do not change the total number of estimated deaths but rather the timing of those deaths. Therefore, discounting only affects the AMI costs after the analysis year and the valuation of premature mortalities that occur after the analysis year. As such, the monetized benefits using a 7% discount rate are only approximately 10% less than the monetized benefits using a 3% discount rate.

The benefit-per-ton estimates are provided in Table 5.9 and the health incidences are provided in Table 5.10. Table 5.11 shows the monetized results using the two epidemiology-based estimates as well as the 12 expert-based estimates. Figure 5.6 provides a graphical breakdown of the $PM_{2.5}$ co-benefits by sector. Figure 5.7 provides a graphical representation of all 14 of the $PM_{2.5}$ co-benefits, at both a 3 percent and 7 percent discount rate.

Table 5.9: $PM_{2.5}$ Co-benefits associated with reducing SO_2 emissions (2006$)*

$PM_{2.5}$ Precursor	Benefit per Ton Estimate (Pope)	Benefit per Ton Estimate (Laden)
SO_2 EGU:	$42,000	$100,000
SO_2 non-EGU:	$30,000	$74,000
SO_2 area:	$19,000	$47,000

*Estimates have been rounded to two significant figures. Confidence intervals are not available for benefit per-ton estimates. Estimates shown use a 3% discount rate. Estimates at a 7% discount rate would be approximately 9% lower.

Table 5.10: Summary of Reductions in Health Incidences from $PM_{2.5}$ Co-Benefits to Attain Alternate Standard Levels in 2020*

	50 ppb	75 ppb	100 ppb
Avoided Premature Mortality			
Pope	5,100	2,300	1,100
Laden	13,000	5,900	2,900
Woodruff (Infant Mortality)	20	9	5
Avoided Morbidity			
Chronic Bronchitis	3,500	1,600	780
Acute Myocardial Infarction	8,600	3,900	1,900
Hospital Admissions, Respiratory	1,300	570	280
Hospital Admissions, Cardiovascular	2,800	1,300	620
Emergency Room Visits, Respiratory	4,900	2,200	1,100
Acute Bronchitis	8,200	3,700	1,800
Work Loss Days	650,000	290,000	150,000
Asthma Exacerbation	90,000	41,000	20,000
Acute Respiratory Symptoms	3,900,000	1,700,000	870,000
Lower Respiratory Symptoms	98,000	44,000	22,000
Upper Respiratory Symptoms	74,000	33,000	17,000

*All estimates are for the analysis year (2020) and are rounded to two significant figures. All fine particles are assumed to have equivalent health effects, but each $PM_{2.5}$ precursor pollutant has a different propensity to form $PM_{2.5}$. These results reflect full attainment with the various standard levels, including extrapolated tons, which were spread across the sectors in proportion to the emissions in the county.

Table 5.11: All $PM_{2.5}$ Co-Benefits Estimates to Attain Alternate Standard Levels in 2020 at discount rates of 3% and 7% (in millions of 2006$)*

	50 ppb		**75 ppb**		**100 ppb**	
	3%	7%	3%	7%	3%	7%
Benefit-per-ton Coefficients Derived from Epidemiology Literature						
Pope et al.	$34,000	$31,000	$15,000	$14,000	$7,400	$6,700
Laden et al.	$83,000	$75,000	$37,000	$34,000	$18,000	$16,000
Benefit-per-ton Coefficients Derived from Expert Elicitation						
Expert A	$88,000	$79,000	$40,000	$36,000	$19,000	$17,000
Expert B	$67,000	$61,000	$30,000	$27,000	$15,000	$13,000
Expert C	$67,000	$60,000	$30,000	$27,000	$15,000	$13,000
Expert D	$47,000	$43,000	$21,000	$19,000	$10,000	$9,400
Expert E	$110,000	$98,000	$49,000	$44,000	$24,000	$21,000
Expert F	$61,000	$55,000	$27,000	$25,000	$13,000	$12,000
Expert G	$40,000	$36,000	$18,000	$16,000	$8,700	$7,900
Expert H	$50,000	$46,000	$23,000	$21,000	$11,000	$9,900
Expert I	$66,000	$60,000	$30,000	$27,000	$14,000	$13,000
Expert J	$54,000	$49,000	$24,000	$22,000	$12,000	$11,000
Expert K	$13,000	$12,000	$5,900	$5,400	$2,900	$2,600
Expert L	$49,000	$44,000	$22,000	$20,000	$11,000	$9,600

*All estimates are rounded to two significant figures. Estimates do not include confidence intervals because they were derived through the benefit-per-ton technique described above. The benefits estimates from the Expert Elicitation are provided as a reasonable characterization of the uncertainty in the mortality estimates associated with the concentration-response function. These results reflect full attainment with the various standard levels, including extrapolated tons, which were spread across the sectors in proportion to the emissions in the county.

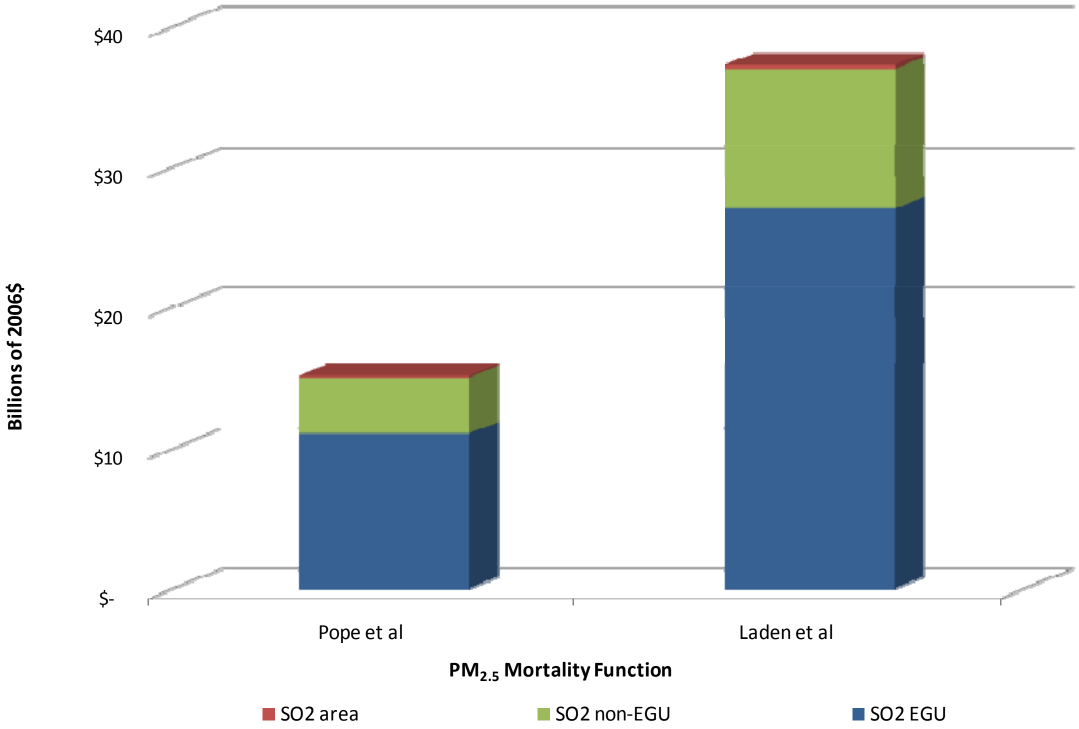
In Table 5.12, we present the results of sensitivity analyses for the PM co-benefits. We indicate each input parameter, the value used as the default, and the values for the sensitivity analyses, and then we provide the total monetary benefits for each input and the percent change from the default value.

Table 5.12: Sensitivity Analyses for $PM_{2.5}$ Health Co-Benefits to Fully Attain 75 ppb

		Total $PM_{2.5}$ Co-Benefits (billions of 2006$)	% Change from Default
Threshold Assumption (with Epidemiology Study)	No Threshold (Pope)	$15	N/A
	No Threshold (Laden)	$37	N/A
	Threshold (Pope)*	$10	-33%
	Threshold (Laden)*	$22	-41%
Discount Rate (with Epidemiology Study)	3% (Pope)	$15	N/A
	3% (Laden)	$37	N/A
	7% (Pope)	$14	-8%
	7% (Laden)	$34	-9%
Simulated Attainment (using Pope)	Full attainment	$15	N/A
	Partial Attainment	$14	-7%

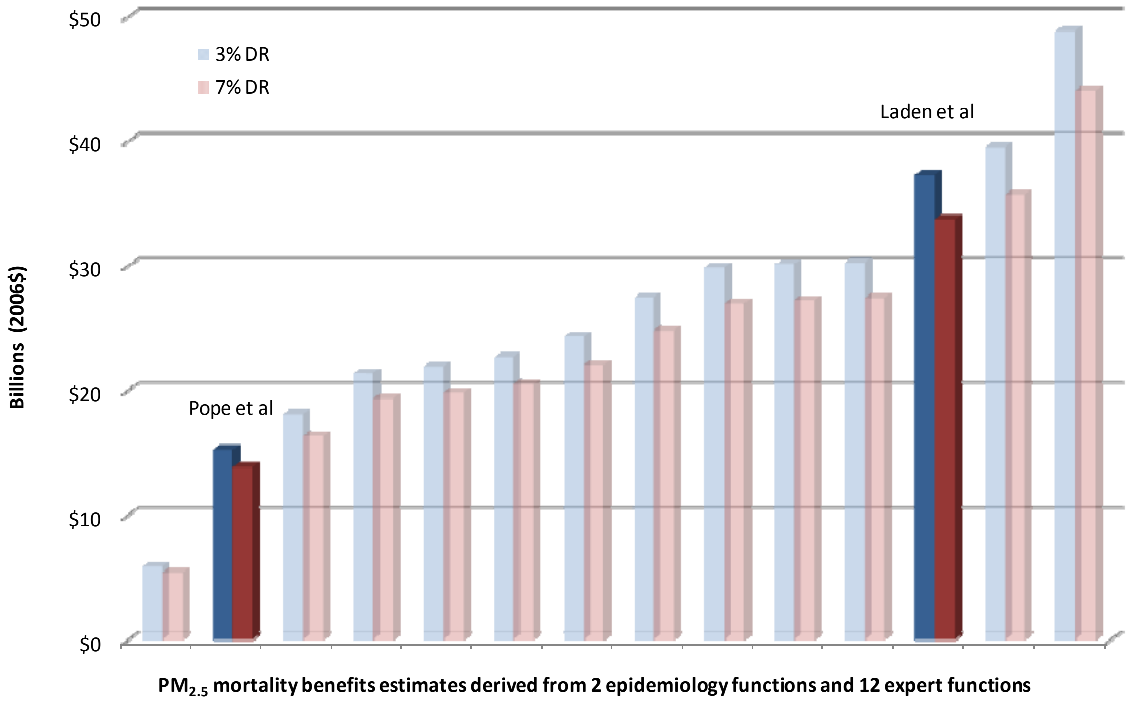
*The Threshold model is not directly comparable to the no-threshold model. The threshold model estimates do not include two technical updates, and they are based on data for 2015, instead of 2020. Directly comparable estimates are not available.

Figure 5.6: Monetized $PM_{2.5}$ Co-Benefits of Fully Attaining 75 ppb by $PM_{2.5}$ Precursor



* All estimates are for the analysis year (2020). All fine particles are assumed to have equivalent health effects, but each $PM_{2.5}$ precursor pollutant has a different propensity to form $PM_{2.5}$. Results using a 7% discount rate would show a similar breakdown. These results reflect full attainment with the various standard levels, including extrapolated tons, which were spread across the sectors in proportion to the emissions in the county.

Figure 5.7: Monetized $PM_{2.5}$ Co-Benefits of Fully Attaining 75 ppb*



* This graph shows the estimated co- benefits in 2020 for the selected standard of 75 ppb using the no-threshold model at discount rates of 3% and 7% using effect coefficients derived from the Pope et al. study and the Laden et al. study, as well as 12 effect coefficients derived from EPA's expert elicitation on PM mortality. The results shown are not the direct results from the studies or expert elicitation; rather, the estimates are based in part on the concentration-response function provided in those studies. Graphs for alternative standards would show a similar pattern. These results reflect full attainment with the various standard levels, including extrapolated tons, which were spread across the sectors in proportion to the emissions in the county.

5.8 Summary of Total Monetized Benefits (SO_2 and $PM_{2.5}$)

EPA estimated the monetized human health benefits of reducing cases of morbidity and premature mortality among populations exposed to SO_2 and $PM_{2.5}$ in 2020 for each of the alternative standard levels in 2006$. For the selected SO_2 standard at 75 ppb, the total monetized benefits would be $15 to $37 billion at a 3% discount rate and $14 to $34 billion at a 7% discount rate.

All of the results in this chapter present benefits estimates that assume full attainment with the alternative standard levels. Partial attainment only incorporates the emission reductions from identified controls without the extrapolated emission reductions.[14] These results are shown in Table 5.13 along with the full attainment at discount rates of 3% and 7%. Table 5.14 shows the total incidences of avoided health effects. Figure 5.8 provides a graphical

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[14] See Chapter 4 for more information regarding the control strategy, including the identified and extrapolated emission reductions.

representation of all 14 total monetized benefits estimates, at both a 3 percent and 7 percent discount rate, for the selected standard of 75 ppb, respectively.

Table 5.13: Total Monetized Benefits to attain Alternate Standard Levels at Discount Rates of 3% and 7% for Full and Partial Attainment (millions of 2006$)[a,c]

		SO_2	$PM_{2.5}$ (Pope)	$PM_{2.5}$ (Laden)	TOTAL (with Pope)	TOTAL (with Laden)
50 ppb	3% Full Attainment	$8.5	$34,000	$83,000	$34,000	$83,000
	7% Full Attainment	$8.5	$31,000	$75,000	$31,000	$75,000
	3% Partial Attainment	-[b]	$30,000	$74,000	$30,000	$74,000
	7% Partial Attainment	-[b]	$28,000	$67,000	$28,000	$67,000
75 ppb	3% Full Attainment	$2.2	$15,000	$37,000	$15,000	$37,000
	7% Full Attainment	$2.2	$14,000	$34,000	$14,000	$34,000
	3% Partial Attainment	-[b]	$14,000	$35,000	$14,000	$35,000
	7% Partial Attainment	-[b]	$13,000	$31,000	$13,000	$31,000
100 ppb	3% Full Attainment	$0.62	$7,400	$18,000	$7,400	$18,000
	7% Full Attainment	$0.62	$6,700	$16,000	$6,700	$16,000
	3% Partial Attainment	-[b]	$6,900	$17,000	$6,900	$17,000
	7% Partial Attainment	-[b]	$6,200	$15,000	$6,200	$15,000

[a] Estimates have been rounded to two significant figures and therefore summation may not match table estimates.

[b] The approach used to simulate air quality changes for SO_2 did not provide the data needed to distinguish partial attainment benefits from full attainment benefits from reduced SO_2 exposure. Therefore, a portion of the SO_2 benefits is attributable to the known controls and a portion of the SO_2 benefits are attributable to the extrapolated controls.

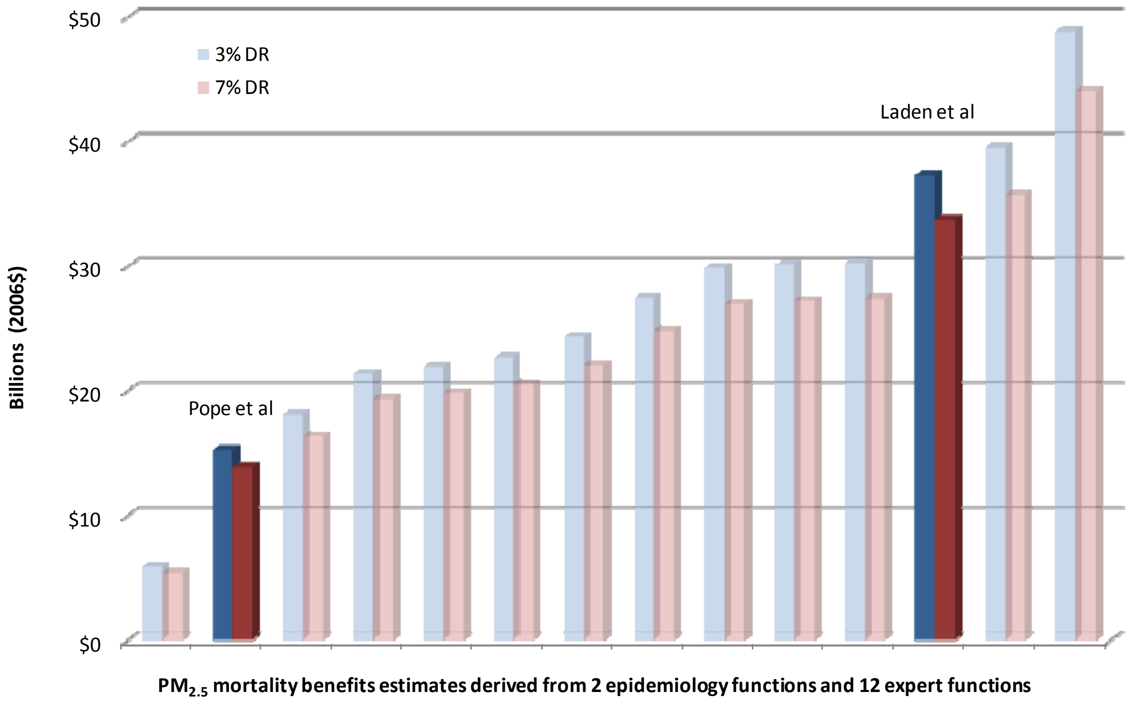
[c] These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. Reductions in SO_2 emissions from multiple sectors to meet the SO_2 NAAQS would primarily reduce the sulfate fraction of $PM_{2.5}$. Because this rule targets a specific particle precursor (i.e., SO_2), this introduces some uncertainty into the results of the analysis.

Table 5.14: Summary of Reductions in Health Incidences from SO_2 and $PM_{2.5}$ to attain Alternate Standard Levels*

	50 ppb	75 ppb	100 ppb
Avoided Premature Mortality			
Pope	5,100	2,300	1,100
Laden	13,000	5,900	2,900
Woodruff (Infant Mortality)	20	9	5
Avoided Morbidity			
Chronic Bronchitis	3,500	1,600	780
Acute Myocardial Infarction	8,600	3,900	1,900
Hospital Admissions, Respiratory	1,400	570	280
Hospital Admissions, Cardiovascular	2,800	1,300	620
Emergency Room Visits, Respiratory	5,800	2,500	1,200
Acute Bronchitis	8,200	3,700	1,800
Work Loss Days	650,000	290,000	150,000
Asthma Exacerbation	150,000	54,000	24,000
Acute Respiratory Symptoms	3,900,000	1,700,000	870,000
Lower Respiratory Symptoms	98,000	44,000	22,000
Upper Respiratory Symptoms	74,000	33,000	17,000

*All estimates are for the analysis year (2020) and are rounded to two significant figures. All fine particles are assumed to have equivalent health effects, but each $PM_{2.5}$ precursor pollutant has a different propensity to form $PM_{2.5}$. These results reflect full attainment with the various standard levels, including extrapolated tons, which were spread across the sectors in proportion to the emissions in the county.

Figure 5.8: Total Monetized Benefits (SO_2 and $PM_{2.5}$) of Fully Attaining 75 ppb in 2020*



* This graphs shows the estimated total monetized benefits in 2020 for the selected standard of 75 ppb using the no-threshold model at discount rates of 3% and 7% using effect coefficients derived from the Pope et al. study and the Laden et al. study, as well as 12 effect coefficients derived from EPA's expert elicitation on PM mortality. The results shown are not the direct results from the studies or expert elicitation; rather, the estimates are based in part on the concentration-response function provided in those studies. Graphs for alternative standards would show a similar pattern.

5.9 Unquantified Welfare Benefits

The monetized benefits estimated in this RIA only reflect the portion of benefits attributable to the health effect reductions associated with ambient fine particles and direct exposure to SO_2. Data, resource, and methodological limitations prevented EPA from quantifying or monetizing the benefits from several important benefit categories, including benefits from reducing ecosystem effects and visibility impairment. In this section, we provide a qualitative assessment of two welfare benefit categories: ecosystem benefits of reducing sulfur deposition and visibility improvements.

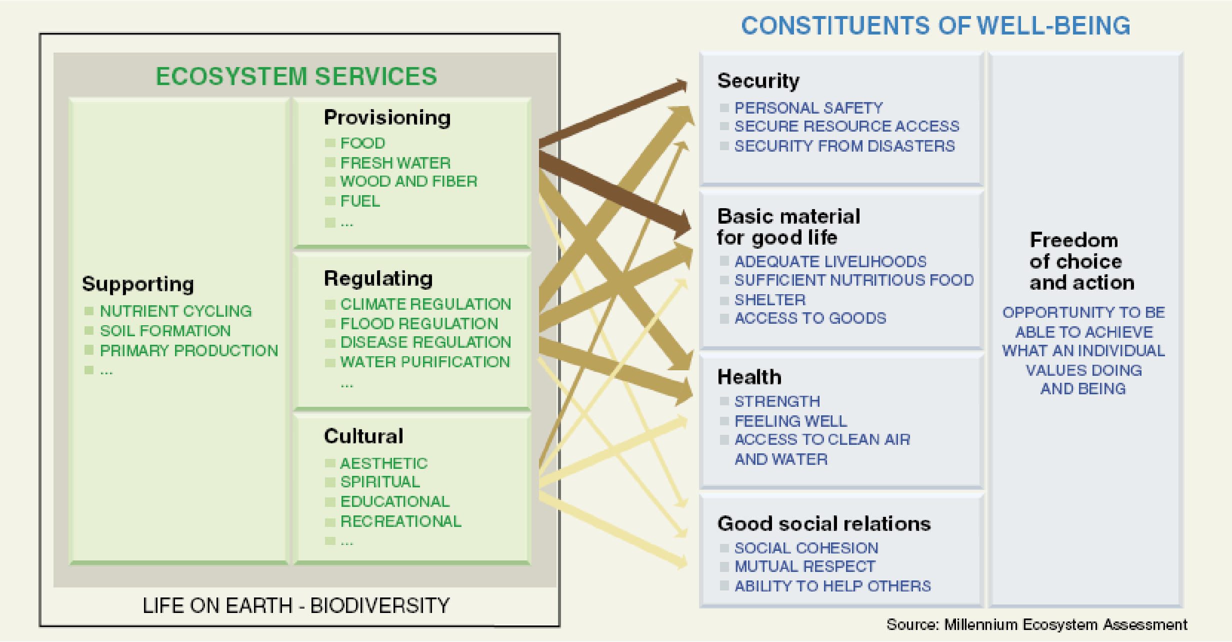
5.9.1 Ecosystem Benefits of Reduced Sulfur Deposition

Ecosystem services can be generally defined as the benefits that individuals and organizations obtain from ecosystems. EPA has defined ecological goods and services as the "outputs of ecological functions or processes that directly or indirectly contribute to social welfare or have the potential to do so in the future. Some outputs may be bought and sold, but most are not marketed" (U.S. EPA, 2006c). Figure 5.9 provides the Millennium Ecosystem Assessment's schematic demonstrating the connections between the categories of ecosystem services and human well-being. The interrelatedness of these categories means that any one ecosystem may provide multiple services. Changes in these services can affect human well-being by affecting security, health, social relationships, and access to basic material goods (MEA, 2005).

In the Millennium Ecosystem Assessment (MEA, 2005), ecosystem services are classified into four main categories:

1. Provisioning: Products obtained from ecosystems, such as the production of food and water
2. Regulating: Benefits obtained from the regulation of ecosystem processes, such as the control of climate and disease
3. Cultural: Nonmaterial benefits that people obtain from ecosystems through spiritual enrichment, cognitive development, reflection, recreation, and aesthetic experiences
4. Supporting: Services necessary for the production of all other ecosystem services, such as nutrient cycles and crop pollination

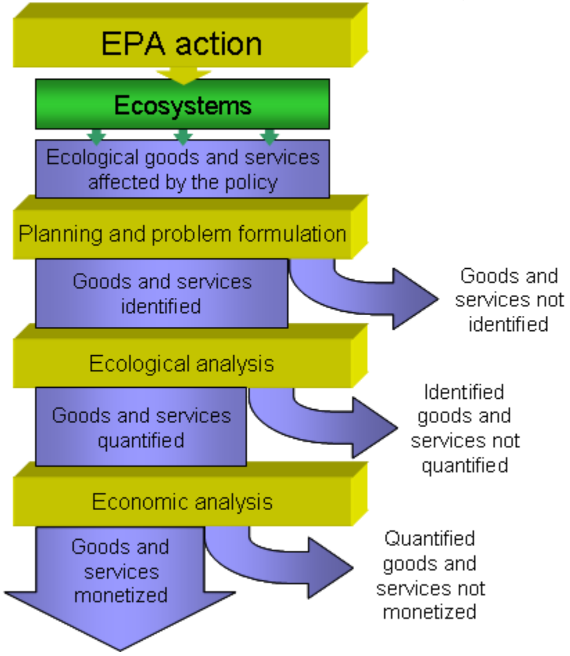
Figure 5.9. Linkages between categories of ecosystem services and components of human well-being from Millennium Ecosystem Assessment (MEA, 2005)



Source: Millennium Ecosystem Assessment

The monetization of ecosystem services generally involves estimating the value of ecological goods and services based on what people are willing to pay (WTP) to increase ecological services or by what people are willing to accept (WTA) in compensation for reductions in them (U.S. EPA, 2006c). There are three primary approaches for estimating the monetary value of ecosystem services: market-based approaches, revealed preference methods, and stated preference methods (U.S. EPA, 2006c). Because economic valuation of ecosystem services can be difficult, nonmonetary valuation using biophysical measurements and concepts also can be used. An example of a nonmonetary valuation method is the use of relative-value indicators (e.g., a flow chart indicating uses of a water body, such as boatable, fishable, swimmable, etc.). It is necessary to recognize that in the analysis of the environmental responses associated with any particular policy or environmental management action, only a subset of the ecosystem services likely to be affected are readily identified. Of those ecosystem services that are identified, only a subset of the changes can be quantified. Within those services whose changes can be quantified, only a few will likely be monetized, and many will remain nonmonetized. The stepwise concept leading up to the valuation of ecosystems services is graphically depicted in Figure 5.10.

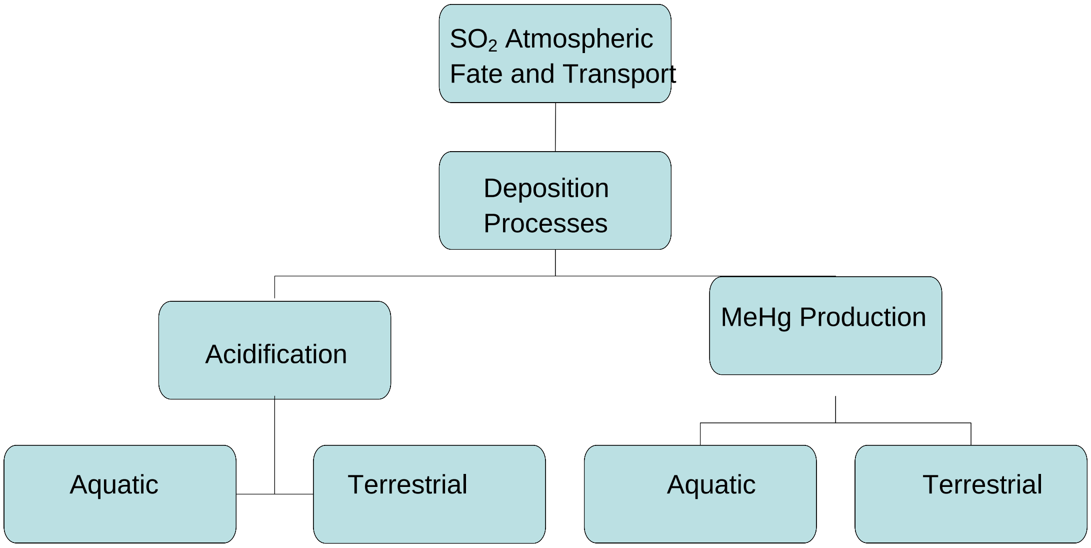
Figure 5.10: Schematic of the benefits assessment process (U.S. EPA, 2006c)



Science of Sulfur Deposition

Sulfur emissions occur over large regions of North America. Once these pollutants are lofted to the middle and upper troposphere, they typically have a much longer lifetime and, with the generally stronger winds at these altitudes, can be transported long distances from their source regions. The length scale of this transport is highly variable owing to differing chemical and meteorological conditions encountered along the transport path (U.S. EPA, 2008f). Sulfur is primarily emitted as SO_2, and secondary particles are formed from SO_X gaseous emissions and associated chemical reactions in the atmosphere. Deposition can occur in either a wet (i.e., rain, snow, sleet, hail, clouds, or fog) or dry form (i.e., gases or particles). Together these emissions are deposited onto terrestrial and aquatic ecosystems across the U.S., contributing to the problems of acidification, nutrient enrichment, and methylmercury production as represented in Figure 5-11.

Figure 5-11: Schematic of Ecological Effects of Sulfur Deposition



The lifetimes of particles vary with particle size. Accumulation-mode particles such as sulfates are kept in suspension by normal air motions and have a lower deposition velocity than coarse-mode particles; they can be transported thousands of kilometers and remain in the atmosphere for a number of days. They are removed from the atmosphere primarily by cloud processes. Particulates affect acid deposition by serving as cloud condensation nuclei and contribute directly to the acidification of rain. In addition, the gas-phase species that lead to the dry deposition of acidity are also precursors of particles. Therefore, reductions in SO_2 emissions will decrease both acid deposition and PM concentrations, but not necessarily in a linear fashion (U.S. EPA, 2008f). Sulfuric acid is also deposited on surfaces by dry deposition and can contribute to environmental effects (U.S. EPA, 2008f).

Ecological Effects of Acidification

Deposition of sulfur can cause acidification, which alters biogeochemistry and affects animal and plant life in terrestrial and aquatic ecosystems across the U.S. Soil acidification is a natural process, but is often accelerated by acidifying deposition, which can decrease concentrations of exchangeable base cations in soils (U.S. EPA, 2008f). Major terrestrial effects include a decline in sensitive tree species, such as red spruce (*Picea rubens*) and sugar maple (*Acer saccharum*) (U.S. EPA, 2008f). Biological effects of acidification in terrestrial ecosystems are generally linked to aluminum toxicity and decreased ability of plant roots to take up base cations (U.S. EPA, 2008f). Decreases in the acid neutralizing capacity and increases in inorganic aluminum concentration contribute to declines in zooplankton, macro invertebrates, and fish species richness in aquatic ecosystems (U.S. EPA, 2008f).

Geology (particularly surficial geology) is the principal factor governing the sensitivity of terrestrial and aquatic ecosystems to acidification from sulfur deposition (U.S. EPA, 2008f). Geologic formations having low base cation supply generally underlie the watersheds of acid-sensitive lakes and streams. Other factors contribute to the sensitivity of soils and surface waters to acidifying deposition, including topography, soil chemistry, land use, and hydrologic flow path (U.S. EPA, 2008f).

Aquatic Ecosystems

Aquatic effects of acidification have been well studied in the U.S. and elsewhere at various trophic levels. These studies indicate that aquatic biota have been affected by acidification at virtually all levels of the food web in acid sensitive aquatic ecosystems. Effects have been most clearly documented for fish, aquatic insects, other invertebrates, and algae. Biological effects are primarily attributable to a combination of low pH and high inorganic aluminum concentrations. Such conditions occur more frequently during rainfall and snowmelt that cause high flows of water and less commonly during low-flow conditions, except where chronic acidity conditions are severe. Biological effects of episodes include reduced fish condition factor[15], changes in species composition and declines in aquatic species richness across multiple taxa, ecosystems and regions. These conditions may also result in direct fish mortality (Van Sickle et al., 1996). Biological effects in aquatic ecosystems can be divided into two major categories: effects on health, vigor, and reproductive success; and effects on biodiversity. Surface water with ANC values greater than 50 µeq/L generally provides moderate protection for most fish (i.e., brook trout, others) and other aquatic organisms (U.S. EPA, 2009c). Table 5-15 provides a summary of the biological effects experienced at various ANC levels.

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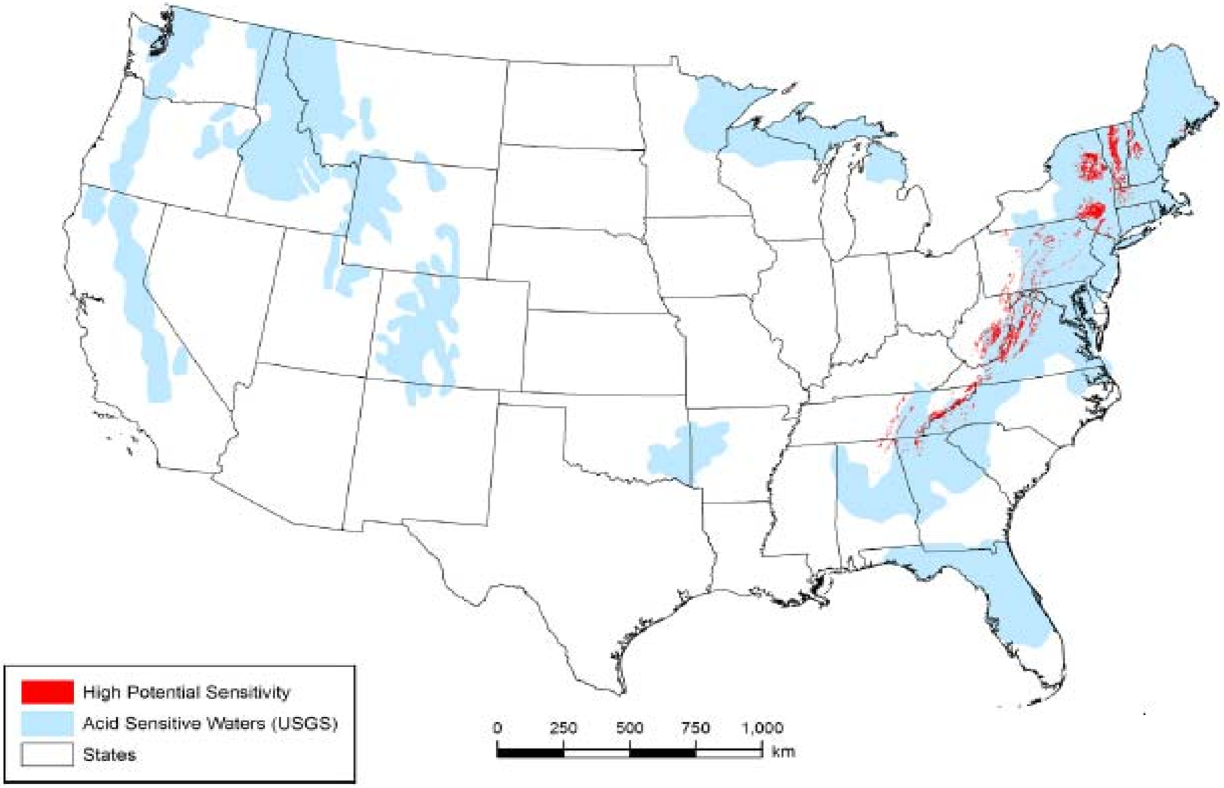
[15] Condition factor is an index that describes the relationship between fish weight and length, and is one measure of sublethal acidification stress that has been used to quantify effects of acidification on an individual fish (U.S.EPA, 2008f).

Table 5-15: Aquatic Status Categories

Category Label	ANC Levels	Expected Ecological Effects
Acute Concern	<0 micro equivalent per Liter (µeq/L)	Near complete loss of fish populations is expected. Planktonic communities have extremely low diversity and are dominated by acidophilic forms. The number of individuals in plankton species that are present is greatly reduced.
Severe Concern	0–20 µeq/L	Highly sensitive to episodic acidification. During episodes of high acidifying deposition, brook trout populations may experience lethal effects. Diversity and distribution of zooplankton communities decline sharply.
Elevated Concern	20–50 µeq/L	Fish species richness is greatly reduced (i.e., more than half of expected species can be missing). On average, brook trout populations experience sublethal effects, including loss of health, reproduction capacity, and fitness. Diversity and distribution of zooplankton communities decline.
Moderate Concern	50–100 µeq/L	Fish species richness begins to decline (i.e., sensitive species are lost from lakes). Brook trout populations are sensitive and variable, with possible sublethal effects. Diversity and distribution of zooplankton communities also begin to decline as species that are sensitive to acidifying deposition are affected.
Low Concern	>100 µeq/L	Fish species richness may be unaffected. Reproducing brook trout populations are expected where habitat is suitable. Zooplankton communities are unaffected and exhibit expected diversity and distribution.

A number of national and regional assessments have been conducted to estimate the distribution and extent of surface water acidity in the U.S (U.S. EPA, 2008f). As a result, several regions of the U.S. have been identified as containing a large number of lakes and streams that are seriously impacted by acidification. Figure 5-12 illustrates those areas of the U.S. where aquatic ecosystems are at risk from acidification.

Figure 5-12: Areas Potentially Sensitive to Aquatic Acidification (U.S. EPA, 2008f)



Because acidification primarily affects the diversity and abundance of aquatic biota, it also affects the ecosystem services that are derived from the fish and other aquatic life found in these surface waters.

While acidification is unlikely to have serious negative effects on, for example, water supplies, it can limit the productivity of surface waters as a source of food (i.e., fish). In the northeastern United States, the surface waters affected by acidification are not a major source of commercially raised or caught fish; however, they are a source of food for some recreational and subsistence fishermen and for other consumers. For example, there is evidence that certain population subgroups in the northeastern United States, such as the Hmong and Chippewa ethnic groups, have particularly high rates of self-caught fish consumption (Hutchison and Kraft, 1994; Peterson et al., 1994). However, it is not known if and how their consumption patterns are affected by the reductions in available fish populations caused by surface water acidification.

Inland surface waters support several cultural services, including aesthetic and educational services and recreational fishing. Recreational fishing in lakes and streams is among the most popular outdoor recreational activities in the northeastern United States.

Based on studies conducted in the northeastern United States, Kaval and Loomis (2003) estimated average consumer surplus values per day of $36 for recreational fishing (in 2007 dollars); therefore, the implied total annual value of freshwater fishing in the northeastern United States was $5.1 billion in 2006.[16] For recreation days, consumer surplus value is most commonly measured using recreation demand, travel cost models.

Another estimate of the overarching ecological benefits associated with reducing lake acidification levels in Adirondacks National Park can be derived from the contingent valuation (CV) survey (Banzhaf et al., 2006), which elicited values for specific improvements in acidification-related water quality and ecological conditions in Adirondack lakes. The survey described a base version with minor improvements said to result from the program, and a scope version with large improvements due to the program and a gradually worsening status quo. After adapting and transferring the results of this study and converting the 10-year annual payments to permanent annual payments using discount rates of 3% and 5%, the WTP estimates ranged from $48 to $107 per year per household (in 2004 dollars) for the base version and $54 to $154 for the scope version. Using these estimates, the aggregate annual benefits of eliminating all anthropogenic sources of NO_x and SO_x emissions were estimated to range from $291 million to $829 million (U.S. EPA, 2009c).[17]

In addition, inland surface waters provide a number of regulating services associated with hydrological and climate regulation by providing environments that sustain aquatic food webs. These services are disrupted by the toxic effects of acidification on fish and other aquatic life. Although it is difficult to quantify these services and how they are affected by acidification, some of these services may be captured through measures of provisioning and cultural services.

Terrestrial Ecosystems

Acidifying deposition has altered major biogeochemical processes in the U.S. by increasing the nitrogen and sulfur content of soils, accelerating nitrate and sulfate leaching from soil to drainage waters, depleting base cations (especially calcium and magnesium) from soils, and increasing the mobility of aluminum. Inorganic aluminum is toxic to some tree roots. Plants affected by high levels of aluminum from the soil often have reduced root growth, which restricts the ability of the plant to take up water and nutrients, especially calcium (U. S. EPA, 2008f). These direct effects can, in turn, influence the response of these plants to climatic

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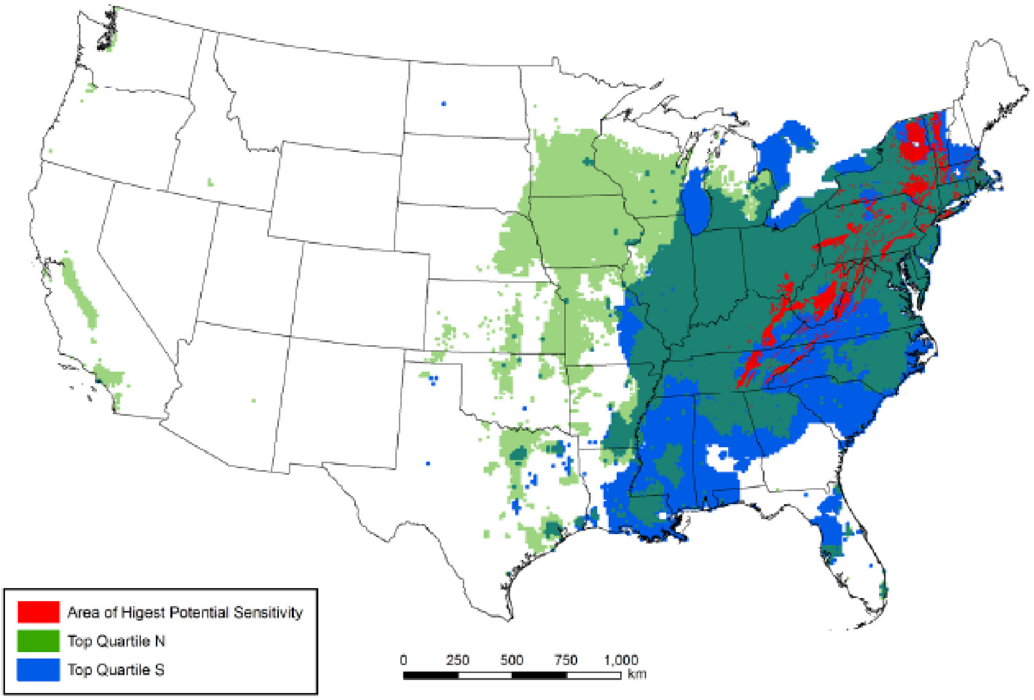
[16] These estimates reflect the total value of the service, not the marginal change in the value of the service as a result of the emission reductions achieved by this rule.

[17] These estimates reflect the total value of the service, not the marginal change in the value of the service as a result of the emission reductions achieved by this rule.

stresses such as droughts and cold temperatures. They can also influence the sensitivity of plants to other stresses, including insect pests and disease (Joslin et al., 1992) leading to increased mortality of canopy trees. In the U.S., terrestrial effects of acidification are best described for forested ecosystems (especially red spruce and sugar maple ecosystems) with additional information on other plant communities, including shrubs and lichen (U.S. EPA, 2008f).

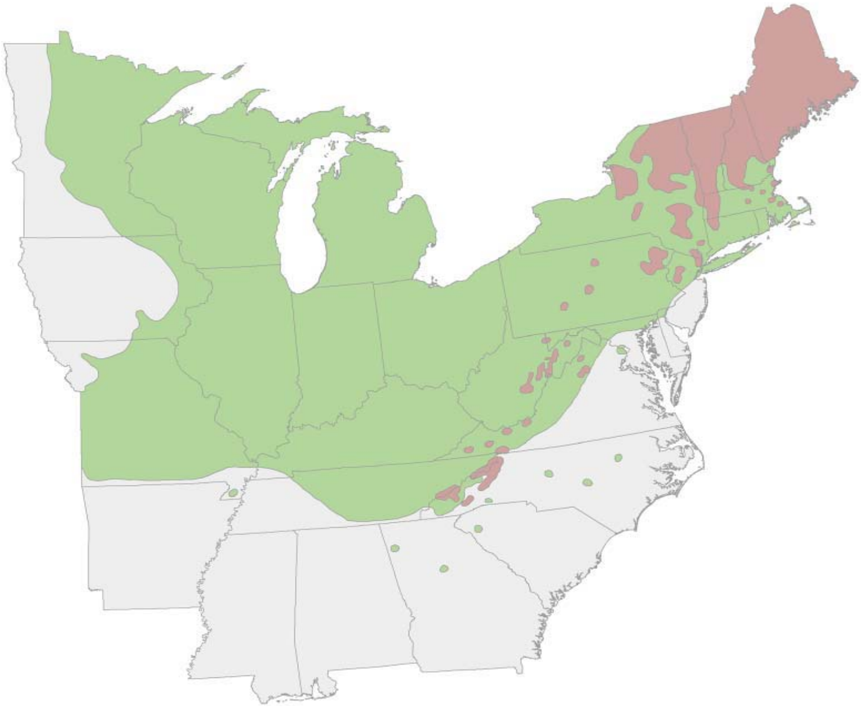
Certain ecosystems in the continental U.S. are potentially sensitive to terrestrial acidification, which is the greatest concern regarding sulfur deposition U.S. EPA (2008f). Figure 5-13 depicts the areas across the U.S. that are potentially sensitive to terrestrial acidification.

Figure 5-13: Areas Potentially Sensitive to Terrestrial Acidification (U.S. EPA, 2008f)



Both coniferous and deciduous forests throughout the eastern U.S. are experiencing gradual losses of base cation nutrients from the soil due to accelerated leaching for acidifying deposition. This change in nutrient availability may reduce the quality of forest nutrition over the long term. Evidence suggests that red spruce and sugar maple in some areas in the eastern U.S. have experienced declining health because of this deposition. For red spruce, (*Picea rubens*) dieback or decline has been observed across high elevation landscapes of the northeastern U.S., and to a lesser extent, the southeastern U.S., and acidifying deposition has been implicated as a causal factor (DeHayes et al., 1999). Figure 5-14 shows the distribution of red spruce (brown) and sugar maple (green) in the eastern U.S.

Figure 5-14: Distribution of Red Spruce (pink) and Sugar Maple (green) in the Eastern U.S. (U.S. EPA, 2008f)



Terrestrial acidification affects several important ecological endpoints, including declines in habitat for threatened and endangered species (cultural), declines in forest aesthetics (cultural), declines in forest productivity (provisioning), and increases in forest soil erosion and reductions in water retention (cultural and regulating).

Forests in the northeastern United States provide several important and valuable provisioning services in the form of tree products. Sugar maples are a particularly important commercial hardwood tree species, providing timber and maple syrup. In the United States, sugar maple saw timber was nearly 900 million board feet in 2006 (USFS, 2006), and annual production of maple syrup was nearly 1.4 million gallons, accounting for approximately 19% of worldwide production. The total annual value of U.S. production in these years was approximately $160 million (NASS, 2008). Red spruce is also used in a variety of products including lumber, pulpwood, poles, plywood, and musical instruments. The total removal of red spruce saw timber from timberland in the United States was over 300 million board feet in 2006 (USFS, 2006).

Forests in the northeastern United States are also an important source of cultural ecosystem services—nonuse (i.e., existence value for threatened and endangered species), recreational, and aesthetic services. Red spruce forests are home to two federally listed species and one delisted species:

1. Spruce-fir moss spider (*Microhexura montivaga*)—endangered
2. Rock gnome lichen (*Gymnoderma lineare*)—endangered
3. Virginia northern flying squirrel (*Glaucomys sabrinus fuscus*)—delisted, but important

Forestlands support a wide variety of outdoor recreational activities, including fishing, hiking, camping, off-road driving, hunting, and wildlife viewing. Regional statistics on recreational activities that are specifically forest based are not available; however, more general data on outdoor recreation provide some insights into the overall level of recreational services provided by forests. More than 30% of the U.S. adult population visited a wilderness or primitive area during the previous year and engaged in day hiking (Cordell et al., 2005). From 1999 to 2004, 16% of adults in the northeastern United States participated in off-road vehicle recreation, for an average of 27 days per year (Cordell et al., 2005). The average consumer surplus value per day of off-road driving in the United States was $25 (in 2007 dollars), and the implied total annual value of off-road driving recreation in the northeastern United States was more than $9 billion (Kaval and Loomis, 2003). More than 5% of adults in the northeastern United States participated in nearly 84 million hunting days (U.S. FWS and U.S. Census Bureau, 2007). Ten percent of adults in northeastern states participated in wildlife viewing away from home on 122 million days in 2006. For these recreational activities in the northeastern United States, Kaval and Loomis (2003) estimated average consumer surplus values per day of $52 for hunting and $34 for wildlife viewing (in 2007 dollars). The implied total annual value of hunting and wildlife viewing in the northeastern United States was, therefore, $4.4 billion and $4.2 billion, respectively, in 2006.

As previously mentioned, it is difficult to estimate the portion of these recreational services that are specifically attributable to forests and to the health of specific tree species. However, one recreational activity that is directly dependent on forest conditions is fall color viewing. Sugar maple trees, in particular, are known for their bright colors and are, therefore, an essential aesthetic component of most fall color landscapes. A survey of residents in the Great Lakes area found that roughly 30% of residents reported at least one trip in the previous year involving fall color viewing (Spencer and Holecek, 2007). In a separate study conducted in Vermont, Brown (2002) reported that more than 22% of households visiting Vermont in 2001 made the trip primarily for viewing fall colors.

Two studies estimated values for protecting high-elevation spruce forests in the southern Appalachian Mountains. Kramer et al. (2003) conducted a contingent valuation study estimating households' WTP for programs to protect remaining high-elevation spruce forests from damages associated with air pollution and insect infestation. Median household WTP was estimated to be roughly $29 (in 2007 dollars) for a smaller program, and $44 for the more extensive program. Jenkins et al. (2002) conducted a very similar study in seven Southern Appalachian states on a potential program to maintain forest conditions at status quo levels. The overall mean annual WTP for the forest protection programs was $208 (in 2007 dollars). Multiplying the average WTP estimate from these studies by the total number of households in the seven-state Appalachian region results in an aggregate annual range of $470 million to $3.4 billion for avoiding a significant decline in the health of high-elevation spruce forests in the Southern Appalachian region.

Forests in the northeastern United States also support and provide a wide variety of valuable regulating services, including soil stabilization and erosion control, water regulation, and climate regulation. The total value of these ecosystem services is very difficult to quantify in a meaningful way, as is the reduction in the value of these services associated with total sulfur deposition. As terrestrial acidification contributes to root damages, reduced biomass growth, and tree mortality, all of these services are likely to be affected; however, the magnitude of these impacts is currently very uncertain.

Ecological Effects of Associated with Sulfate in the Mercury Methylation Process

Mercury is a highly neurotoxic contaminant that enters the food web as a methylated compound, methylmercury (U.S. EPA, 2008f). The contaminant is concentrated in higher trophic levels, including fish eaten by humans. Experimental evidence has established that only inconsequential amounts of methylmercury can be produced in the absence of sulfate (U.S. EPA, 2008f). Many variables influence how much mercury accumulates in fish, but elevated mercury levels in fish can only occur where substantial amounts of methylmercury are present (U.S. EPA, 2008f). Current evidence indicates that in watersheds where mercury is present, increased sulfate deposition very likely results in methylmercury accumulation in fish (Drevnick et al., 2007; Munthe et al., 2007). The ISA for Oxides of Nitrogen and Sulfur: Ecological Criteria ISA concluded that evidence is sufficient to infer a casual relationship between sulfur deposition and increased mercury methylation in wetlands and aquatic environments (U.S. EPA, 2008f).

Establishing the quantitative relationship between sulfate and mercury methylation in natural settings is difficult because of the presence of multiple interacting factors in aquatic and terrestrial environments, including wetlands, aquatic environments where sulfate, sulfur-reducing bacteria (SRB), and inorganic mercury are present (U.S. EPA, 2008f). These are the three primary requirements for bacterially-mediated conversion to methylmercury. Additional factors affecting conversion include the presence of anoxic conditions, temperature, the presence and types of organic matter, the presence and types of mercury-binding species, and watershed effects (e.g., watershed type, land cover, water body limnology, and runoff loading). With regard to methylmercury, the highest concentrations in the environment generally occur at or near the sedimentary surface, below the oxic–anoxic boundary. Although mercury methylation can occur within the water column, there is generally a far greater contribution of mercury methylation from sediments because of anoxia and of greater concentrations of SRB, substrate, and sulfate. Figure 5-15 depicts the mercury cycle.

Figure 5-15: The mercury cycle in an ecosystem (USGS, 2006)

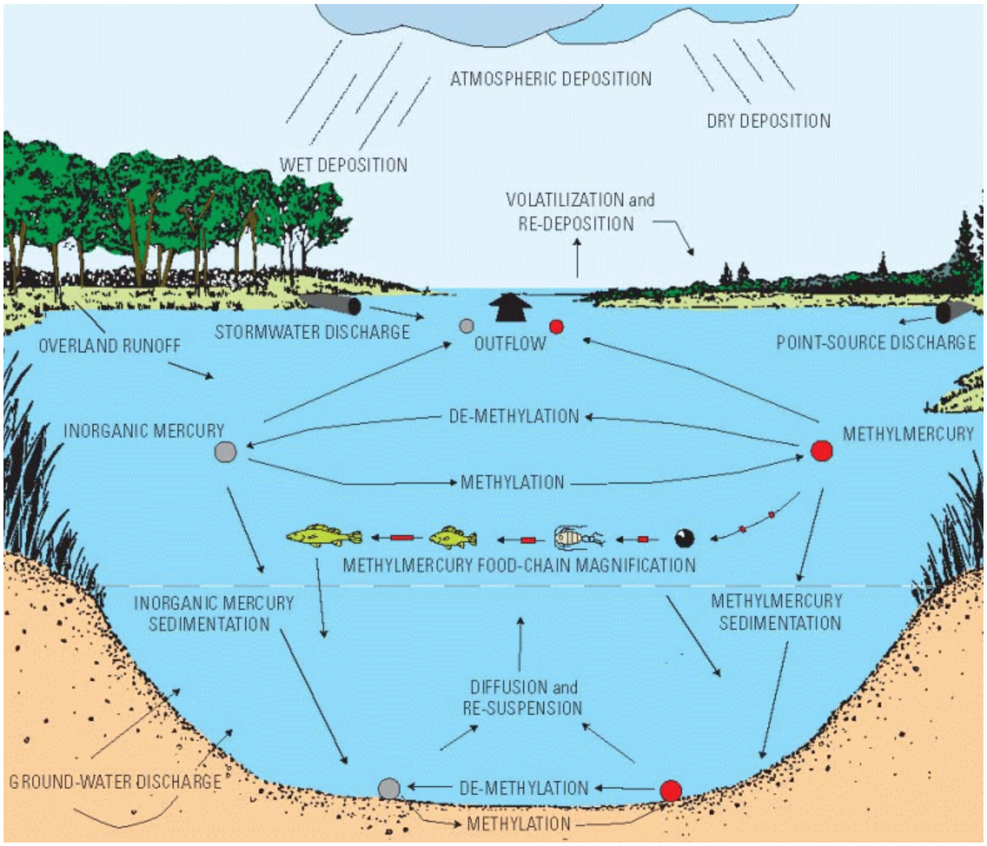
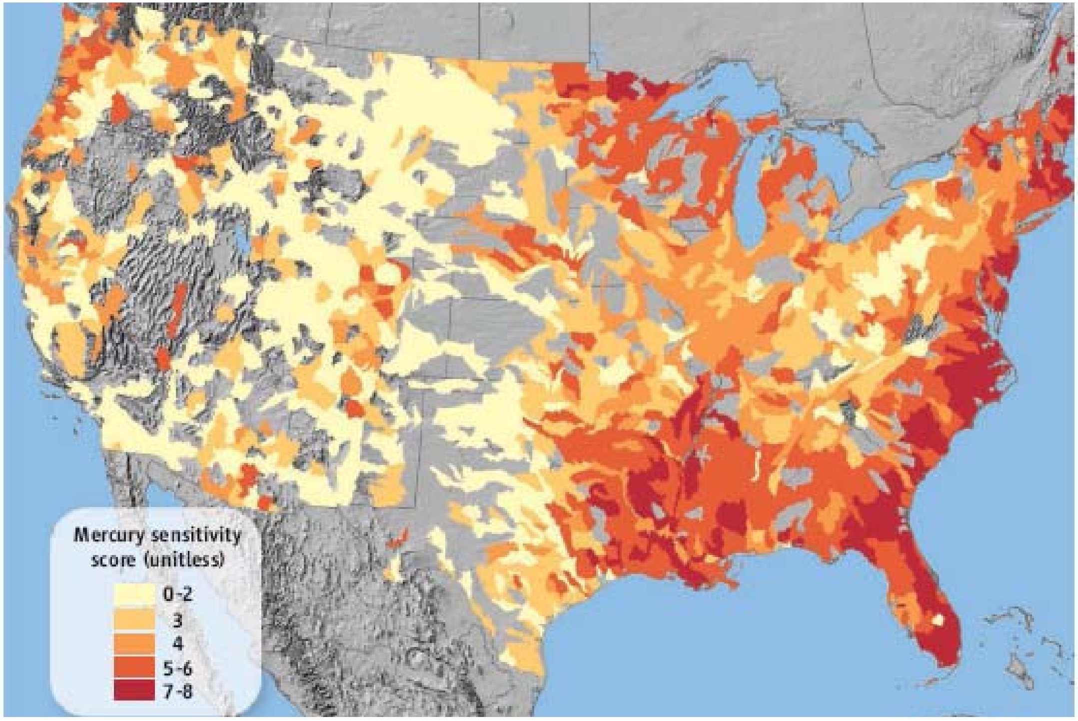


Figure 5-16 illustrates a map of mercury-sensitive watersheds based on sulfate concentrations, ANC, levels of dissolved organic carbon and pH, mercury species concentrations, and soil types to gauge the methylation sensitivity (Myers et al., 2007).

Figure 5.16: Preliminary USGS map of mercury methylation–sensitive watersheds (Myers et al., 2007)



Decreases in sulfate deposition/emissions have already shown reductions in methylmercury (U.S. EPA, 2008f). Observed decreases in methylmercury fish tissue concentrations have been linked to decreased acidification and declining sulfate and mercury deposition (Hrabik and Watras, 2002; Drevnick et al., 2007).

In the U.S., consumption of fish and shellfish are the main sources of methylmercury exposure to humans. Methylmercury builds up more in some types of fish and shellfish than in others. The levels of methylmercury in high and shellfish vary widely depending on what they eat, how long they live, and how high they are in the food chain. Most fish, including ocean species and local freshwater fish, contain some methylmercury. For example, in recent studies by EPA and the U.S. Geological Survey (USGS) of fish tissues, every fish samples contained some methylmercury.

State-level fish consumption advisories for mercury are based on state criteria, many of which are based on EPA's fish tissue criterion for methylmercury (U.S. EPA, 2001) or on U.S. Food and Drug Administration's action levels (U.S. FDA, 2001). In 2008, there were 3,361 fish advisories issued at least in part for mercury contamination (80% of all fish advisories), covering

16.8 million lake acres (40% of total lake acreage) and 1.3 million river miles (35% of total river miles) over all 50 states, one U.S. territory, and 3 tribes (U.S. EPA, 2009f). Recently, the U.S. Geological Survey (USGS) examined mercury levels in top-predator fish, bed sediment, and water from 291 streams across the U.S. (Scudder et al., 2009). USGS detected mercury contamination in every fish sampled, and the concentration of mercury in fish exceeded EPA's criterion in 27% of the sites sampled.

The ecosystem service most directly affected by sulfate-mediated mercury methylation is the provision of fish for consumption as a food source. This service is of particular importance to groups engaged in subsistence fishing, pregnant women and young children. While it is not possible to quantify the reduction in fish consumption due to the presence of methylmercury in fish from sulfur deposition, it is likely, given the number of state advisories and the EPA/FDA guidelines (U.S. EPA/FDA, 2004) on consumption for pregnant women and young children, that this service is negatively affected.

Research shows that most people's fish consumption does not cause a mercury-related health concern. However, certain people may be at higher risk because of their routinely high consumption of fish (e.g., tribal and other subsistence fishers and their families who rely heavily on fish for a substantial part of their diet). It has been demonstrated that high levels of methylmercury in the bloodstream of unborn babies and young children may harm the developing nervous system, making the child less able to think and learn. Moreover, mercury exposure at high levels can harm the brain, heart, kidneys, lungs, and immune system of people of all ages. The majority of fish consumed in the U.S. are ocean species. The methylmercury concentrations in ocean fish species are primarily influences by the global mercury pool. However, the methylmercury found in local fish can be due, at least partly, to mercury emissions from local sources.

Several studies suggest that the methylmercury content of fish may reduce these cardio-protective effects of fish consumption. Some of these studies also suggest that methylmercury may cause adverse effects to the cardiovascular system. For example, the NRC (2000) review of the literature concerning methylmercury health effects took note of two epidemiological studies that found an association between dietary exposure to methylmercury and adverse cardiovascular effects.[18] Moreover, in a study of 1,833 males in Finland aged 42 to 60 years, Solonen et al. (1995) observed a relationship between methylmercury exposure via

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[18] National Research Council (NRC). 2000. Toxicological Effects of Methylmercury. Committee on the Toxicological Effects of Methylmercury, Board on Environmental Studies and Toxicology. National Academies Press. Washington, DC. pp.168-173.

fish consumption and acute myocardial infarction (AMI or heart attacks), coronary heart disease, cardiovascular disease, and all-cause mortality.[19] The NRC also noted a study of 917 seven year old children in the Faroe Islands, whose initial exposure to methylmercury was *in utero* although post natal exposures may have occurred as well. At seven years of age, these children exhibited an increase in blood pressure and a decrease in heart rate variability.[20] Based on these and other studies, NRC concluded in 2000 that, while "the data base is not as extensive for cardiovascular effects as it is for other end points (i.e. neurologic effects) the cardiovascular system appears to be a target for methylmercury toxicity."[21]

Since publication of the NRC report there have been some 30 published papers presenting the findings of studies that have examined the possible cardiovascular effects of methylmercury exposure. These studies include epidemiological, toxicological, and toxicokinetic investigations. Over a dozen review papers have also been published. If there is a causal relationship between methylmercury exposure and adverse cardiovascular effects, then reducing exposure to methylmercury would result in public health benefits from reduced cardiovascular effects.

In early 2010, EPA sponsored a workshop in which a group of experts were asked to assess the plausibility of a causal relationship between methylmercury exposure and cardiovascular health effects and to advise EPA on methodologies for estimating population level cardiovascular health impacts of reduced methylmercury exposure. The report from that workshop is in preparation.

Because establishing the quantitative relationship between sulfate and mercury methylation in natural settings is difficult, we were unable to model the changes in the methylation process, bioaccumulation in fish tissue, and human consumption of mercury-contaminated fish that would be needed in order to estimate the human health benefits from reducing sulfate emissions in this rule.

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[19] Salonen, J.T., Seppanen, K. Nyyssonen et al. 1995. "Intake of mercury from fish lipid peroxidation, and the risk of myocardial infarction and coronary, cardiovascular and any death in Eastern Finnish men." Circulation, 91 (3):645-655.

[20] Sorensen, N, K. Murata, E. Budtz-Jorgensen, P. Weihe, and Grandjean, P., 1999. "Prenatal Methylmercury Exposure As A Cardiovascular Risk Factor At Seven Years of Age", Epidemiology, pp370-375.

[21] National Research Council (NRC). 2000. Toxicological Effects of Methylmercury. Committee on the Toxicological Effects of Methylmercury, Board on Environmental Studies and Toxicology. National Academies Press. Washington, DC. p. 229.

Ecological Effects Associated with Gaseous Sulfur Dioxide

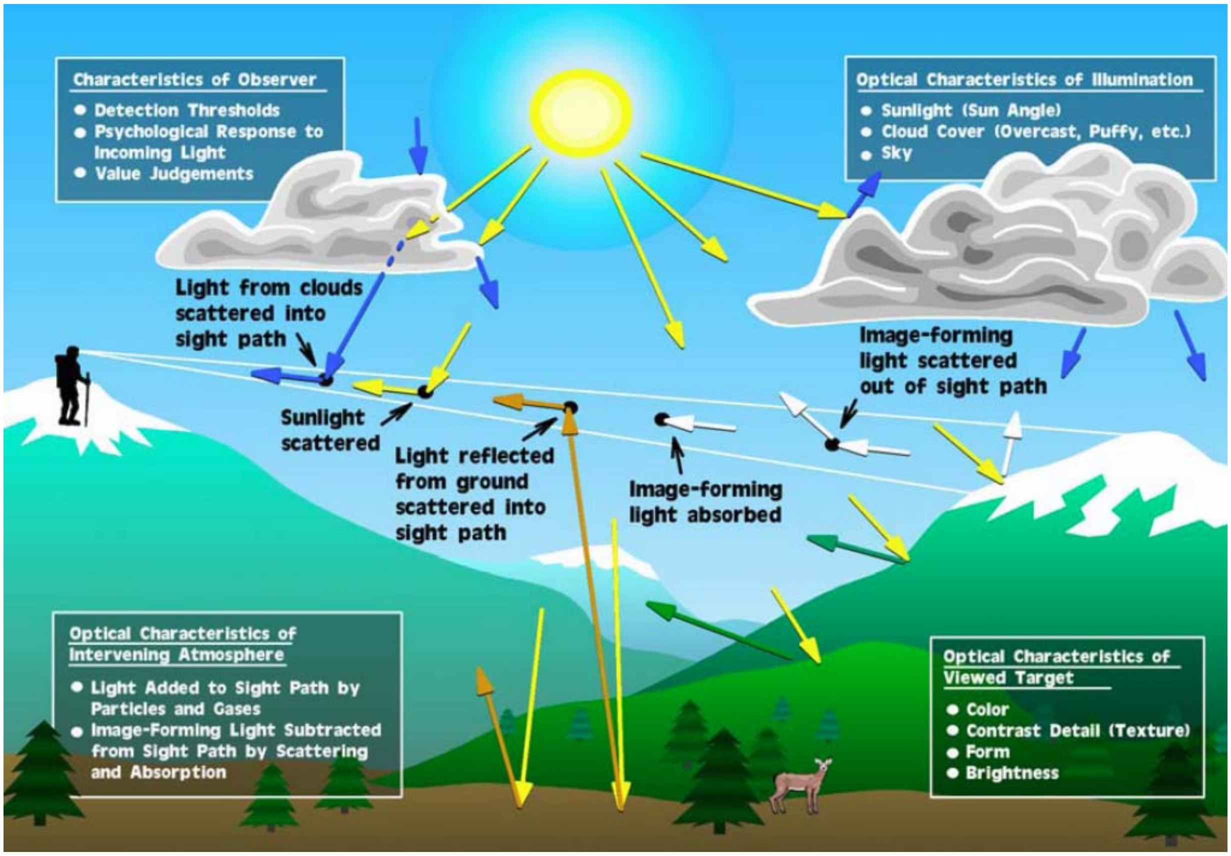
Uptake of gaseous sulfur dioxide in a plant canopy is a complex process involving adsorption to surfaces (leaves, stems, and soil) and absorption into leaves. SO_2 penetrates into leaves through to the stomata, although there is evidence for limited pathways via the cuticle. Pollutants must be transported from the bulk air to the leaf boundary layer in order to get to the stomata. When the stomata are closed, as occurs under dark or drought conditions, resistance to gas uptake is very high and the plant has a very low degree of susceptibility to injury. In contrast, mosses and lichens do not have a protective cuticle barrier to gaseous pollutants or stomates and are generally more sensitive to gaseous sulfur than vascular plants (U.S. EPA, 2008f). Acute foliar injury usually happens within hours of exposure, involves a rapid absorption of a toxic dose, and involves collapse or necrosis of plant tissues. Another type of visible injury is termed chronic injury and is usually a result of variable SO_2 exposures over the growing season. Besides foliar injury, chronic exposure to low SO_2 concentrations can result in reduced photosynthesis, growth, and yield of plants (U.S. EPA, 2008f). These effects are cumulative over the season and are often not associated with visible foliar injury. As with foliar injury, these effects vary among species and growing environment. SO_2 is also considered the primary factor causing the death of lichens in many urban and industrial areas (Hutchinson et al., 1996).

5.9.2 Visibility Improvements

Reductions in SO_2 emissions and secondary formation of $PM_{2.5}$ due to the alternative standards will improve the level of visibility throughout the United States. These suspended particles and gases degrade visibility by scattering and absorbing light. Visibility directly affects people's enjoyment of a variety of daily activities. Individuals value visibility both in the places they live and work, in the places they travel to for recreational purposes, and at sites of unique public value, such as the Great Smokey Mountains National Park. Without the necessary air quality data, we were unable to calculate the predicted change in visibility due to control strategy to attain various alternate standard levels. However, in this section, we describe the process by which SO_2 emissions impair visibility and how this impairment affects the public.

Visual air quality (VAQ) is commonly measured as either light extinction, which is defined as the loss of light per unit of distance in terms of inverse megameters (Mm^{-1}) or the deciview (dv) metric (Pitchford and Malm, 1993), which is a logarithmic function of extinction. Extinction and deciviews are physical measures of the amount of visibility impairment (e.g., the amount of "haze"), with both extinction and deciview increasing as the amount of haze increases. Pitchford and Malm characterize a change of one deciview as "a small but perceptible scenic change under many circumstances." Light extinction is the optical characteristic of the atmosphere that occurs when light is either scattered or absorbed, which converts the light to heat. Particulate matter and gases can both scatter and absorb light. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). The extent to which any amount of light extinction affects a person's ability to view a scene depends on both scene and light characteristics. For example, the appearance of a nearby object (i.e. a building) is generally less sensitive to a change in light extinction than the appearance of a similar object at a greater distance. See Figure 5-17 for an illustration of the important factors affecting visibility.

Figure 5-17: Important factors involved in seeing a scenic vista (Malm, 1999)



In conjunction with the U.S. National Park Service, the U.S. Forest Service, other Federal land managers, and State organizations in the U.S., the U.S. EPA has supported visibility monitoring in national parks and wilderness areas since 1988. The monitoring network known as IMPROVE (Interagency Monitoring of Protected Visual Environments) now includes 150 sites that represent almost all of the Class I areas across the country (see Figure 5-18) (U.S. EPA, 2009d).

Figure 5-18: Mandatory Class I Areas in the U.S.

* Rainbow Lake, WI and Bradwell Bay, FL are Class 1 Areas where visibility is not an important air quality related value

Produced by NPS Air Resources Division

Annual average visibility conditions (reflecting light extinction due to both anthropogenic and non-anthropogenic sources) vary regionally across the U.S. (U.S. EPA, 2009d). The rural East generally has higher levels of impairment than remote sites in the West, with the exception of urban-influenced sites such as San Gorgonio Wilderness (CA) and Point Reyes National Seashore (CA), which have annual average levels comparable to certain sites in the Northeast (U.S. EPA, 2004). Higher visibility impairment levels in the East are due to generally higher concentrations of fine particles, particularly sulfates, and higher average relative humidity levels. While visibility trends have improved in most Class I areas, the recent data show that these areas continue to suffer from visibility impairment. In eastern parks, average visual range has decreased from 90 miles to 15-25 miles, and in the West, visual range has decreased from 140 miles to 35-90 miles (U.S. EPA, 2004; U.S. EPA, 1999b).

Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing (U.S. EPA, 2009d). Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. When the necessary AQ data is available, EPA generally considers benefits from these two categories of visibility changes: residential visibility (i.e., the visibility in and around the locations where people live) and recreational visibility (i.e., visibility at Class I national parks and wilderness areas.) In both cases, economic benefits are believed to consist of use values and nonuse values. Use values include the aesthetic benefits of better visibility, improved road and air safety, and enhanced recreation in activities like hunting and bird watching. Nonuse values are based on people's beliefs that the environment ought to exist free of human-induced haze. Nonuse values may be more important for recreational areas, particularly national parks and monuments. In addition, evidence suggests that an individual's WTP for improvements in visibility at a Class I area is influenced by whether it is in the region in which the individual lives, or whether it is somewhere else (Chestnut and Rowe, 1990). In general, people appear to be willing to pay more for visibility improvements at parks and wilderness areas that are "in-region" than at those that are "out-of-region." This is plausible, because people are more likely to visit, be familiar with, and care about parks and wilderness areas in their own part of the country. EPA generally uses a contingent valuation study as the basis for monetary estimates of the benefits of visibility changes in recreational areas (Chestnut and Rowe, 1990). To estimate the monetized value of visibility changes, an analyst would multiply the willingness-to-pay estimates by the amount of visibility impairment, but this information in unavailable for this analysis.

5.10 Limitations and Uncertainties

The National Research Council (NRC) (2002) concluded that EPA's general methodology for calculating the benefits of reducing air pollution is reasonable and informative in spite of inherent uncertainties. To address these inherent uncertainties, NRC highlighted the need to conduct rigorous quantitative analysis of uncertainty and to present benefits estimates to decisionmakers in ways that foster an appropriate appreciation of their inherent uncertainty. In response to these comments, EPA's Office of Air and Radiation (OAR) is developing a comprehensive strategy for characterizing the aggregate impact of uncertainty in key modeling elements on both health incidence and benefits estimates. Components of that strategy include emissions modeling, air quality modeling, health effects incidence estimation, and valuation.

In this analysis, we use three methods to assess uncertainty quantitatively: Monte Carlo analysis, sensitivity analysis, and alternate concentration-response functions for PM mortality. We also provide a qualitative assessment for those aspects that we are unable to address quantitatively in this analysis. Each of these analyses is described in detail in the following sections.

This analysis includes many data sources as inputs, including emission inventories, air quality data from models (with their associated parameters and inputs), population data, health effect estimates from epidemiology studies, and economic data for monetizing benefits. Each of these inputs may be uncertain and would affect the benefits estimate. When the uncertainties from each stage of the analysis are compounded, small uncertainties can have large effects on the total quantified benefits. In this analysis, we are unable to quantify the cumulative effect of all of these uncertainties, but we provide the following analyses to characterize many of the largest sources of uncertainty.

5.10.1 Monte Carlo analysis

Similar to other recent RIAs, we used Monte Carlo methods for characterizing random sampling error associated with the concentration response functions and economic valuation functions. Monte Carlo simulation uses random sampling from distributions of parameters to characterize the effects of uncertainty on output variables, such as incidence of morbidity. Specifically, we used Monte Carlo methods to generate confidence intervals around the estimated health impact and dollar benefits. The reported standard errors in the epidemiological studies determined the distributions for individual effect estimates, as shown in Table 5.6 for SO_2 benefits. Unfortunately, the associated confidence intervals are not available for the $PM_{2.5}$ co-benefits due to limitations in the benefit-per-ton methodology.

5.10.2 Sensitivity analyses

We performed a variety of sensitivity analyses on the benefits results to assess the sensitivity of the primary results to various data inputs and assumptions. We then changed each default input one at a time and recalculated the total monetized benefits to assess the percent change from the default. In Tables 5.6 and 5.12, we provided the results of this sensitivity analysis. We indicate each input parameter, the value used as the default, and the values for the sensitivity analyses, and then we provide the total monetary benefits for each input and the percent change from the default value. This sensitivity analysis indicates that the results are most sensitive to assumptions regarding the attainment status and the threshold assumption in the PM-mortality relationship, and the results are less sensitive to alternate assumptions regarding the interpolation method, discount rate, and various assumptions regarding SO_2 exposure. To account for the large difference in magnitude between benefits from reduced SO_2 exposure and $PM_{2.5}$ exposure, we provide separate sensitivity analyses. We show the sensitivity analysis for selected standard (75 ppb), but other standard levels would show similar sensitivity to these perturbations, albeit with smaller magnitudes. Descriptions of the sensitivity analyses are provided in the relevant sections of this chapter.

5.10.3 Alternate concentration-response functions for PM mortality

$PM_{2.5}$ mortality co-benefits are the largest benefit category that we monetized in this analysis. To better understand the concentration-response relationship between $PM_{2.5}$ exposure and premature mortality, EPA conducted an expert elicitation in 2006 (Roman et al., 2008; IEc, 2006). In general, the results of the expert elicitation support the conclusion that the benefits of $PM_{2.5}$ control are very likely to be substantial. In previous RIAs, EPA presented benefits estimates using concentration response functions derived from the $PM_{2.5}$ Expert Elicitation as a range from the lowest expert value (Expert K) to the highest expert value (Expert E). However, this approach did not indicate the agency's judgment on what the best estimate of PM benefits may be, and EPA's Science Advisory Board described this presentation as misleading. Therefore, we began to present the cohort-based studies (Pope et al, 2002; and Laden et al., 2006) as our core estimates in the Portland Cement RIA (U.S. EPA, 2009a). Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower benefits estimates are plausible, but most of the expert-based estimates fall between the two epidemiology-based estimates (Roman et al., 2008).

In this analysis, we present the results derived from the expert elicitation as indicative of the uncertainty associated with a major component of the health impact functions, and we provide the independent estimates derived from each of the twelve experts to better characterize the degree of variability in the expert responses. In this chapter, we provide the results using the concentration-response functions derived from the expert elicitation in both tabular (Table 5.11) and graphical form (Figure 5.1). Please note that these results are not the direct results from the studies or expert elicitation; rather, the estimates are based in part on the concentration-response function provided in those studies. Because in this RIA we estimate PM co-benefits using benefit-per-ton estimates, technical limitations prevent us from providing the associated credible intervals with the expert functions.

5.10.4 Qualitative assessment of uncertainty and other analysis limitations

Although we strive to incorporate as many quantitative assessments of uncertainty, there are several aspects for which we are only able to address qualitatively. These aspects are important factors to consider when evaluating the relative benefits of the attainment strategies for each of the alternative standards:

1. The 12 km by 12 km resolution of the air quality modeling grid may be too coarse to accurately estimate the potential near-field health benefits of reducing SO_2 emissions. These uncertainties likely result in an underestimate of the SO_2-related benefits.
2. The interpolation techniques used to estimate the full attainment benefits from reduced SO_2 exposure of the alternative standards contributed some uncertainty to the analysis. The great majority of benefits estimated for the various standard levels were derived through interpolation. As noted previously in this chapter, these benefits are likely to be more uncertain than if we had modeled the air quality scenario for both SO_2 and $PM_{2.5}$. In general, the VNA interpolation approach will underestimate benefits because it does not account for the broader spatial distribution of air quality changes that may occur due to the implementation of a regional emission control program.
3. There are many uncertainties associated with the health impact functions used in this modeling effort. These include: within study variability (the precision with which a given study estimates the relationship between air quality changes and health effects); across study variation (different published studies of the same pollutant/health effect relationship typically do not report identical findings and in some instances the differences are substantial); the application of C-R functions nationwide (does not account for any relationship between region and health effect, to the extent that such a relationship exists); extrapolation of impact functions across population (we assumed that certain health impact functions applied to age ranges broader than that considered in the original epidemiological study); and various uncertainties in the C-R function, including causality and thresholds. These uncertainties may under- or over-estimate benefits.
4. Co-pollutants present in the ambient air may have contributed to the health effects attributed to SO_2 in single pollutant models. Risks attributed to SO_2 might be overestimated where concentration-response functions are based on single pollutant models. If co-pollutants are highly correlated with SO_2, their inclusion in an SO_2 health effects model can lead to misleading conclusions in identifying a specific causal pollutant. Because this collinearity exists, many of the studies reported statistically insignificant effect estimates for both SO_2 and the co-pollutants; this is due in part to the loss of statistical power as these models control for co-pollutants. Where available, we have selected multipollutant effect estimates to control for the potential confounding effects of co-pollutants; these include NYDOH (2006), Schwartz et al. (1994) and O'Connor et al. (2008). The remaining studies include single pollutant models.
5. This analysis is for the year 2020, and projecting key variables introduces uncertainty. Inherent in any analysis of future regulatory programs are uncertainties in projecting

atmospheric conditions and source level emissions, as well as population, health baselines, incomes, technology, and other factors.

6. This analysis omits certain unquantified effects due to lack of data, time and resources. These unquantified endpoints include other health effects, ecosystem effects, and visibility. EPA will continue to evaluate new methods and models and select those most appropriate for estimating the benefits of reductions in air pollution. Enhanced collaboration between air quality modelers, epidemiologists, toxicologists, ecologists, and economists should result in a more tightly integrated analytical framework for measuring benefits of air pollution policies.
7. $PM_{2.5}$ co-benefits represent a substantial proportion of total monetized benefits (over 99% of total monetized benefits), and these estimates are subject to a number of assumptions and uncertainties.
    a. $PM_{2.5}$ co-benefits were derived through benefit per-ton estimates, which do not reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors that might lead to an over-estimate or under-estimate of the actual benefits of controlling directly emitted fine particulates.
    b. We assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because $PM_{2.5}$ produced via transported precursors emitted from EGUs may differ significantly from direct $PM_{2.5}$ released from diesel engines and other industrial sources, but no clear scientific grounds exist for supporting differential effects estimates by particle type.
    c. We assume that the health impact function for fine particles is linear down to the lowest air quality levels modeled in this analysis. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of $PM_{2.5,}$ including both regions that are in attainment with fine particle standard and those that do not meet the standard down to the lowest modeled concentrations.
    d. To characterize the uncertainty in the relationship between $PM_{2.5}$ and premature mortality, we include a set of twelve estimates based on results of the expert elicitation study in addition to our core estimates. Even these multiple characterizations omit the uncertainty in air quality estimates, baseline incidence rates, populations exposed and transferability of the effect estimate to diverse locations. As a result, the reported confidence intervals and range of estimates give an incomplete picture about the overall uncertainty in the $PM_{2.5}$ estimates.

This information should be interpreted within the context of the larger uncertainty surrounding the entire analysis. For more information on the uncertainties associated with $PM_{2.5}$ co-benefits, please consult the $PM_{2.5}$ NAAQS RIA (Table 5.5).

5.11 Discussion

The results of this benefits analysis suggest that fully attaining the selected SO_2 standard of 75 ppb would produce important health benefits from reduced SO_2 exposure in the form of fewer respiratory hospitalizations, respiratory emergency department visits and cases of acute respiratory symptoms. In addition, attaining the selected SO_2 standard standards would also produce substantial health co-benefits from reducing $PM_{2.5}$ exposure in the form of avoided premature mortality and other morbidity effects.

The proposal version of this analysis was the first time that EPA has estimated the monetized human health benefits of reducing exposure to SO_2 to support a change in the NAAQS. In contrast to recent $PM_{2.5}$ and ozone-related benefits assessments, there was far less analytical precedent on which to base this assessment. For this reason, we developed entirely new components of the health impact analysis, including the identification of health endpoints to be quantified and the selection of relevant effect estimates within the epidemiology literature. Because we did not receive any substantive comments on this approach during the comment period, we duplicated this methodology using the updated air quality estimates for the final RIA. As the SO_2 health literature continues to evolve, EPA will reassess the health endpoints and risk estimates used in this analysis.

While the monetized benefits of reduced SO_2 exposure appear small when compared to the monetized benefits of reduced $PM_{2.5}$ exposure, readers should not necessarily infer that the total monetized benefits of attaining a new SO_2 standard are minimal. As shown in Table 5.13, the monetized $PM_{2.5}$ co-benefits represent over 99% of the total monetized benefits. This result is consistent with other recent RIAs, where the $PM_{2.5}$ co-benefits represent a large proportion of total monetized benefits. This result is amplified in this RIA by the decision not to quantify SO_2-related premature mortality and other morbidity endpoints due to the uncertainties associated with estimating those endpoints. Studies have shown that there is a relationship between SO_2 exposure and premature mortality, but that relationship is limited by potential confounding. Because premature mortality generally comprises over 90% of the total monetized benefits, this decision may substantially underestimate the monetized health benefits of reduced SO_2 exposure.

We were unable to quantify the benefits from several welfare benefit categories. We lacked the necessary air quality data to quantify the benefits from improvements in visibility from reducing light-scattering particles. Previous RIAs for ozone (U.S. EPA, 2008a) and $PM_{2.5}$ (U.S. EPA, 2006a) indicate that visibility is an important benefit category, and previous efforts to monetize those benefits have only included a subset of visibility benefits, excluding benefits in urban areas and many national and state parks. Even this subset accounted for up to 5% of total monetized benefits in the Ozone NAAQS RIA (U.S. EPA, 2008a).

We were also unable to quantify the ecosystem benefits of reduced sulfur deposition because we lacked the necessary air quality data and resources to run the ecosystem benefits models. Previous assessments (U.S. EPA, 1999a; U.S. EPA, 2005; U.S. EPA, 2009e) indicate that ecosystem benefits are also an important benefits category, but those efforts were only able to monetize a tiny subset of ecosystem benefits in specific geographic locations, such as recreational fishing effects from lake acidification in the Adirondacks. We were also unable to quantify the benefits of decreased mercury methylation from sulfate deposition. Quantifying the relationship between sulfate and mercury methylation in natural settings is difficult, but some studies have shown that decreasing sulfate deposition can also decrease methylmercury.

In section 5.7 of this RIA, we discuss the revised presentation using benefits based on Pope et al. and Laden et al. as the core estimates instead of using the range based on the low and high end of the expert elicitation. This change was incorporated in direct response to recommendations from EPA's Science Advisory Board (U.S.EPA-SAB, 2008). Although using benefit-per-ton estimates limited our ability to incorporate all of their suggestions fully, we have incorporated the following recommendations into this analysis:

- Added "bottom line" statements where appropriate
- Clarified that the benefits results shown are not the actual judgments of the experts
- Acknowledged uncertainties exist at each stage of the analytic process, although difficult to quantify when using benefit-per-ton estimates
- Did not use the expert elicitation range to characterize the uncertainty as it focuses on the most extreme judgments with zero weight to all the others,
- Described the rationale for using expert elicitation in the context of the regulatory process (to characterize uncertainty)
- Identified results based on epidemiology studies and expert elicitation separately
- Showed central mass of expert opinion using graphs
- Presented the quantitative results using diverse tables and more graphics

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Chapter 6: Cost Analysis Approach and Results

Synopsis

This chapter describes our illustrative analysis of the engineering costs and monitoring costs associated with attaining the final and alternative standards for the National Ambient Air Quality Standard (NAAQS) for SO_2. We present our analysis of these costs in four separate sections. Section 6.1 presents the cost estimates. Sections 6.2 and 6.3 summarize the illustrative economic and energy impacts of these standards, respectively, while Section 6.4 outlines the main limitations of the analysis. As mentioned previously, the analysis is presented here for the final standard of 75 ppb, and two alternative standards: 50 ppb and 100 ppb in the year 2020.

Section 6.1 breaks out discussion of cost estimates into five subsections. The first subsection summarizes the data and methods that we employed to estimate the costs associated with the control strategies outlined in Chapter 4. The second subsection presents county level estimates of the costs of identified controls associated with the regulatory alternatives examined in this RIA. Following this discussion, the third subsection describes the approach used to estimate the extrapolated costs of unspecified emission reductions that may be needed to comply with the final and alternative standards. The fourth subsection provides a brief discussion of the monitoring costs associated with the final NAAQS. The fifth subsection provides the estimated total costs of the regulatory alternatives examined. This section concludes with a discussion of technological innovation and how that affects regulatory cost estimates.

This analysis does not estimate the projected attainment status of areas of the country other than those counties currently served by one of the approximately 349 monitors with complete data in the current network. It is important to note that the final rule will require a monitoring network wholly comprised of monitors sited at locations of expected maximum hourly concentrations. Only about one third of the existing SO_2 network may be source-oriented and/or in the locations of maximum concentration required by the final rule because the current network is focused on population areas and community-wide ambient levels of SO_2. Actual monitored levels using the new monitoring network may be higher than levels measured using the existing network. We recognize that once a network of monitors located at maximum-concentration is put in place, more areas could find themselves exceeding the new SO_2 NAAQS. However for this RIA analysis, we lack sufficient data to predict which counties might exceed the new NAAQS after implementation of the new monitoring network. Therefore we lack a credible analytic path to estimating costs and benefits for such a future scenario.

In addition, this chapter presents cost estimates associated with both identified control measures and unspecified emission reductions needed to reach attainment. Identified control measures include known measures for known sources that may be implemented to attain the alternative standard, whereas the achievement of unspecified emission reductions requires implementation of hypothetical additional measures in areas that would not attain the selected standard following the implementation of identified controls to known sources.

Note that the universe of sources achieving unspecified emission reductions beyond identified controls is not completely understood; therefore we are not able to identify known control devices, work practices, or other control measures to achieve these reductions. We calculated extrapolated costs for unspecified emission reductions using a fixed cost per ton approach. The analysis presents hypothetical costs of attaining the SO_2 NAAQS, subject to States' abilities to find emission reductions whose costs are finite, although likely to be higher than those of the identified control measures we believe to exist. Section 6.1 below describes in more detail our approaches for estimating both the costs of identified controls and the extrapolated costs of unspecified emission reductions needed beyond identified controls.

As is discussed throughout this RIA, the technologies and control strategies selected for this analysis are illustrative of one approach that nonattainment areas may employ to comply with the revised SO_2 standard. Potential control programs may be designed and implemented in a number of ways, and EPA anticipates that State and Local governments will consider those programs that are best suited for local conditions. As such, the costs described in this chapter generally cover the annualized costs of purchasing, installing, and operating the referenced technologies. We also present monitoring costs. Because we are uncertain of the specific actions that State Agencies will take to design State Implementation Plans to meet the revised standard, we do not estimate the costs that government agencies may incur to implement these control strategies.

6.1 Engineering Cost Estimates

6.1.1 Data and Methods: Identified Control Costs

Consistent with the emissions control strategy analysis presented in Chapter 4, our analysis of the costs associated with the final SO_2 NAAQS focuses SO_2 emission controls for EGU sources first, then nonEGU point sources, and then area sources.

6.1.1.1 EGU Sources

We used equations for wet FGD scrubber controls used in the Integrated Planning Model (IPM) to estimate the control cost for SO_2 reductions from EGUs. Equations are available for estimating capital and annual costs, and these equations are dependent on unit capacity and capacity factor (fraction of hours in a year that an EGU operates). Annual costs for control measures applied in IPM include those for fixed and variable operating and maintenance (O&M) items and annualized capital costs calculated using a capital recovery factor and are specifically applicable to EGUs.

6.1.1.2 NonEGU Point and Area Sources

After designing the hypothetical control strategy using the methodology discussed in Chapter 4, EPA used the Control Strategy Tool (CoST) and AirControlNET to estimate engineering control costs for nonEGU and Area sources. CoST calculates engineering costs using three different methods: (1) by multiplying an average annualized cost per ton estimate against the total tons of a pollutant reduced to derive a total cost estimate; (2) by calculating cost using an equation that incorporates key plant information; or (3) by using both cost per ton and cost equations. Most control cost information within CoST has been developed based on the cost per ton approach. This is because estimating engineering costs using an equation requires more data, and parameters used in other non-cost per ton methods may not be readily available or broadly representative across sources within the emissions inventory. The costing equations used in CoST require either plant capacity or stack flow to determine annual, capital and/or operating and maintenance (O&M) costs. Capital costs are converted to annual costs using the capital recovery factor (CRF)[1]. Where possible, cost calculations are used to calculate total annual control cost (TACC) which is a function of the capital (CC) and O&M costs. The capital recovery factor incorporates the interest rate and equipment life (in years) of the control equipment. Operating costs are calculated as a function of annual O&M and other variable costs. The resulting TACC equation is TACC = (CRF * CC) + O&M.

Engineering costs will differ based upon quantity of emissions reduced, plant capacity, or stack flow which can vary by emissions inventory year. Engineering costs will also differ in a nominal sense by the year the costs are calculated for (i.e., 1999$ versus 2006$).[2] For capital

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[1] For more information on this cost methodology and the role of AirControlNET in control strategy analysis, see Section 6 of the 2006 PM RIA, AirControlNET 4.1 Control Measures Documentation (Pechan, 2006b), or the EPA Air Pollution Control Cost Manual, Section 1, Chapter 2, found at http://www.epa.gov/ttn/catc/products.html#cccinfo.

[2] The engineering costs will not be any different in a real (inflation-adjusted) sense if calculated in 2006 versus 1999 dollars if properly escalated. For this analysis, all costs are reported in real 2006 dollars.

investment, we do not assume early capital investment in order to attain standards by 2020. For 2020, our estimate of annualized costs represents a “snapshot” of the annualized costs, which include annualized capital and O&M costs, for those controls included in our identified control strategy analysis. Our engineering cost analysis uses the equivalent uniform annual costs (EUAC) method, in which annualized costs are calculated based on the equipment life for the control measure along with the interest rate by use of the CRF as mentioned previously in this chapter. Annualized costs are estimated as equal for each year the control is expected to operate. Hence, our annualized costs for nonEGU point and area sources estimated for 2020 are the same whether the control measure is installed in 2019 or in 2010. We make no presumption of additional capital investment in years beyond 2020. The EUAC method is discussed in detail in the EPA Air Pollution Control Cost Manual[3]. Applied controls and their respective engineering costs are provided in the SO_2 NAAQS docket.

6.1.2 Identified Control Strategy Analysis Engineering Costs

In this section, we provide engineering cost estimates of the control strategies identified in Chapter 4 that include control measures applied to nonEGU sources, area sources, and EGUs. Engineering costs generally refer to the expense of capital equipment installation, the site preparation costs for the application, and annual operating and maintenance costs.

The total annualized cost of control in each geographic area of our analysis for the hypothetical control scenario is provided in Table 6.1. These numbers reflect the engineering costs across all sectors. Estimates are annualized at a discount rate of 7%.

Table 6.1 summarizes these costs in total and by sector nationwide. As indicated in the table, the estimated annualized costs of these controls under the 75 ppb final standard in 2020 are $960 million per year (2006$). For the other 2 alternative standards examined, in 2020 the annualized costs range from $470 million to $2,600 million. Consistent with Chapter 4's summary of the air quality impacts associated with identified controls, the cost estimates in Table 6.1 reflect partial attainment with the alternative standard being examined in this RIA. Consistent with the identified control strategy analysis emission reductions presented in Chapter 4, a majority of the costs are from controls applied to EGU sources, but a relatively large share of costs is borne by nonEGU point sources.

The costs of the EGU strategy reflect application of controls (described in Chapter 4) where needed to obtain as much reductions as possible to attain each alternative standard.

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[3] http://epa.gov/ttn/catc/products.html#cccinfo

Table 6.2 presents the identified control costs in 2020 by county for each alternative standard. These costs are shown for a 7 percent discount rate.

Table 6.1: Annual Control Costs of Identified Controls in 2020 in Total and by Sector (Millions of 2006$) [a, b]

	50 ppb	75 ppb	100 ppb
Total Costs for Identified Controls[c, d]	$ 2,600	$ 960	$ 470
EGUs	$ 1,700	$ 700	$ 300
nonEGUs	$ 900	$ 260	$ 170
Area Sources	$ 40	$ 0.55	$ 0.24

[a] All estimates rounded to two significant figures. As such, totals will not sum down columns.

[b] All estimates provided reflect the engineering cost of the identified control strategy analysis, incremental to a 2020 baseline.

[c] Total annualized costs were calculated using a 7% discount rate

[d] These values represent partial attainment costs for the identified control strategy analysis. There were locations not able to attain the alternative standard being analyzed with identified controls only.

Table 6.2: Identified Controls – Total Annual Cost by County in 2020 (Millions of 2006$)[a,b,c,d]

state	county	50 ppb	75 ppb	100 ppb
Arizona	Gila Co	$8.8	$8.8	$8.8
Colorado	Denver Co	$39.0		
Connecticut	New Haven Co	$8.2		
Florida	Duval Co	$24.0		
Florida	Hillsborough Co	$3.2		
Georgia	Chatham Co	$42.0	$12.0	
Idaho	Bannock Co	$0.6		
Illinois	Cook Co	$16.0		
Illinois	Madison Co	$65.0	$31.0	
Illinois	St Clair Co			
Illinois	Sangamon Co	$60.0	$30.0	
Illinois	Tazewell Co	$120.0	$27.0	
Indiana	Floyd Co	$0.14		
Indiana	Fountain Co	$19.0		
Indiana	Jasper Co			
Indiana	Lake Co	$210.0	$49.0	
Indiana	Morgan Co	$10.0		
Indiana	Porter Co			
Indiana	Wayne Co	$47.0	$47.0	$35.0
Iowa	Linn Co	$26.0	$18.0	
Iowa	Muscatine Co	$89.0	$65.0	$31.0
Kentucky	Jefferson Co	$85.0		
Kentucky	Livingston Co	$11.0		
Louisiana	East Baton Rouge Par	$29.0		

state	county	50 ppb	75 ppb	100 ppb
Missouri	Greene Co	$16.0		
Missouri	Jackson Co	$59.0	$26.0	
Missouri	Jefferson Co	$310.0	$280.0	$280.0
Montana	Yellowstone Co	$12.0		
Nebraska	Douglas Co	$17.0	$17.0	
New Hampshire	Merrimack Co	$19.0		
New York	Erie Co	$38.0	$14.0	
New York	Monroe Co	$7.5		
New York	Suffolk Co	$50.0	$21.0	
North Carolina	New Hanover Co	$19.0		
Ohio	Clark Co	$19.0		
Ohio	Jefferson Co	$18.0		
Ohio	Lake Co	$110.0	$47.0	
Ohio	Summit Co	$76.0	$19.0	$3.0
Oklahoma	Kay Co	$28.0		
Oklahoma	Muskogee Co	$78.0	$51.0	$25.0
Oklahoma	Tulsa Co	$24.0		
Pennsylvania	Allegheny Co	$160.0		
Pennsylvania	Blair Co	$38.0		
Pennsylvania	Northampton Co	$61.0	$28.0	
Pennsylvania	Warren Co	$29.0	$29.0	$29.0
South Carolina	Lexington Co	$22.0		
Tennessee	Blount Co	$36.0		
Tennessee	Bradley Co	$39.0	$2.9	
Tennessee	Montgomery Co	$38.0	$38.0	$38.0
Tennessee	Shelby Co	$16.0		
Tennessee	Sullivan Co	$110.0	$47.0	
Texas	Harris Co	$66.0		
Texas	Jefferson Co	$61.0	$28.0	
West Virginia	Hancock Co	$30.0		
Wisconsin	Brown Co	$40.0		
Wisconsin	Oneida Co	$22.0	$22.0	$22.0

[a] All estimates rounded to two significant figures. As such, totals will not sum down columns.

[b] All estimates provided reflect the engineering cost of the identified control strategy analysis, incremental to a 2020 baseline.

[c] Total annualized costs were calculated using a 7% discount rate.

[d] These values represent partial attainment costs for the identified control strategy analysis. There were locations not able to attain the alternative standard being analyzed with identified controls only.

6.1.3 Extrapolated Costs

Prior to presenting the methodology for estimating costs for unspecified emission reductions, it is important to provide information from EPA's Science Advisory Board (SAB) Council Advisory on the issue of estimating costs of unidentified control measures.[4]

> *812 Council Advisory, Direct Cost Report, Unidentified Measures (charge question 2.a):*
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> *"The Project Team has been unable to identify measures that yield sufficient emission reductions to comply with the National Ambient Air Quality Standards (NAAQS) and relies on unidentified pollution control measures to make up the difference. Emission reductions attributed to unidentified measures appear to account for a large share of emission reductions required for a few large metropolitan areas but a relatively small share of emission reductions in other locations and nationwide.*
>
> *"The Council agrees with the Project Team that there is little credibility and hence limited value to assigning costs to these unidentified measures. It suggests taking great care in reporting cost estimates in cases where unidentified measures account for a significant share of emission reductions. At a minimum, the components of the total cost associated with identified and unidentified measures should be clearly distinguished. In some cases, it may be preferable to not quantify the costs of unidentified measures and to simply report the quantity and share of emissions reductions attributed to these measures.*
>
> *"When assigning costs to unidentified measures, the Council suggests that a simple, transparent method that is sensitive to the degree of uncertainty about these costs is best. Of the three approaches outlined, assuming a fixed cost/ton appears to be the*

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[4] U.S. Environmental Protection Agency, Advisory Council on Clean Air Compliance Analysis (COUNCIL), *Council Advisory on OAR's Direct Cost Report and Uncertainty Analysis Plan*, Washington, DC. June 8, 2007.

> *simplest and most straightforward. Uncertainty might be represented using alternative fixed costs per ton of emissions avoided."*

EPA has considered this advice and the requirements of E.O. 12866 and OMB circular A-4, which provides guidance on the estimation of benefits and costs of regulations.

As indicated above the identified control costs do not result in attainment of the selected or alternative standards in four areas. In these areas, unspecified emission reductions needed beyond identified controls will likely be necessary to reach attainment.

Taking into consideration the above SAB advice, we estimated the costs of unspecified future emission reductions using a fixed (annualized) cost per ton approach. In previous analyses we have estimated the extrapolated costs using other marginal cost based approaches in addition to the fixed cost per ton approach. We examine the data available for each analysis and determine on a case by case basis the appropriate extrapolation technique. Due to the limited number of control measures applied in this analysis across all sectors, we concluded that it would not be credible to establish a marginal cost-based approach or a representative value for the costs of further SO_2 emission reductions. We also recognize that the emissions from EGUs are the largest for these areas. In addition, there is also limited information on SO_2 controls applied to non-EGUs beyond the scope of this analysis, especially for small sources. For these reasons, we have relied upon a simple fixed cost approach utilized for that analysis to represent the fixed cost of unspecified emission reductions for this analysis. The primary estimate presented is $15,000 (2006$), with sensitivities of $10,000/ton and $20,000/ton. Use of $15,000/ton as a fixed cost estimate is commensurate with the cost of nonEGU SO_2 control measures as applied in the $PM_{2.5}$ RIA three years ago. This fixed costs is also much higher than reported costs for SO_2 controls such as wet FGD scrubbers for industrial boilers are reported to be up to at least $5,200/ton (2006$).[5] Also, this estimate is considerably greater than the current and futures prices for SO_2 emissions allowances traded for compliance with the CAIR program.[6] Finally, as

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[5] Applicability and Feasibility of NOx, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers. NESCAUM, November 2008. Available on the Internet at http://www.nescaum.org/documents/ici-boilers-20081118-final.pdf/.

[6] The Evolving SO2 Allowance Market: Title IV, CAIR, and Beyond. Palmer, Karen, Resources for the Future and Evans, David, US EPA/OPEI, July 13, 2009. Available on the Internet at http://www.rff.org/Publications/WPC/Pages/090713-Evolving-SO2-Allowance-Market.aspx.

mentioned above, the use of a fixed cost per ton of $15,000/ton is consistent with what an advisory committee to the Section 812 second prospective analysis on the Clean Air Act Amendments suggested in June 2007 for estimating the costs of reductions from unidentified controls.

The estimation of costs for emission reductions needed to reach attainment many years in the future is inherently difficult. We expect that additional control measures that we were not able to identify may be developed by 2020. As described later in this chapter, our experience with Clean Air Act implementation shows that technological advances and development of innovative strategies can make possible cost effective emissions reductions that are unforeseen today, and can reduce costs of some emerging technologies over time. But we cannot precisely predict the amount of technology advance in the future. The relationship of the cost of additional future controls to the cost of control options available today is not at all clear. Available, currently known control measures increase in costs per ton beyond the range of what has ever been implemented and because they are not currently required can not serve as an accurate representation of expected costs of implementation. Such measures would still not provide the needed additional control for full attainment in the analysis year 2020. History has shown that when faced with potentially costly controls requirements, firms could adapt by changing their production process or innovate to develop more cost effective ways of meeting control requirements. We recognize that a single fixed cost of control of $15,000 per ton of emissions reductions does not account for the significant emissions cuts that are necessary in some areas and so its use provides an estimate that is likely to differ from actual future costs. Yet, the limited emission controls dataset applied for the identified control strategy analysis significantly limits our ability to estimate full attainment costs using more sophisticated methods.

In the economics literature there are a variety of theoretical ways to estimate the cost of more stringent emissions reductions than can be achieved by known technologies. One method would be to estimate the cost of reducing all remaining tons by simply extrapolating the cost curve using data on cost and effectiveness of all known controls. This method can imply the last ton of reductions costs an amount which is thousands of times higher than the fixed cost presumed above (i.e., $15,000 per ton). This result is highly unlikely given the uncertainty surrounding the assumptions implicit in this estimate (e.g. projecting 10 years into the future, not including factors for technological innovation and improvements, not including societal and economy wide changes from dealing with climate change). Such a result does not necessarily mean that such costs will be incurred, because of uncertainties about future control technology, economic activity and the possibility of deferment of full attainment dates. Another variant on this approach is to develop a method which simulates technological change by causing shifts in the cost curve over time to reflect that innovation can reduce costs of control.

In addition, it is theoretically possible to consider the cost of a geographic area changing to a different type of economic structure over time (e.g. moving from a one type of manufacturing to another or from manufacturing to a more service oriented economy) as another way to predict the cost of meeting a tighter standard. This would be a challenging, data intensive exercise that would be very area specific. Nationwide estimates would have to be built from an area by area basis. In some areas, mobile sources may be a significant source of emissions; some areas are experimenting with congestion pricing as a means of restructuring how people and goods travel to reduce emissions.

In the absence of more robust methods for estimating these costs, EPA is following the SAB advice to keep the approach simple and transparent. If commentors have different assumptions about the cost of attainment, it is easy for them to calculate the cost of attaining a tighter standard using the fixed cost formula. EPA is going to continue to work on most robust methods of developing these estimates. EPA will continue to improve methods of estimating the costs of full attainment when health-based standards require emissions cuts greater than can be achieved by all known engineering controls. Over the course of the next several months EPA, in partnership with OMB and interested federal agencies will be investigating different ways of estimating these extrapolated full attainment costs, including consideration of ways of incorporating technological change and other factors. In addition, EPA is looking into developing approaches to characterize different future states of the world. These scenarios (similar to the goal of the IPCC scenarios for the outcome of climate change, for example) would allow us to consider a range of possibilities. Many criteria pollutant emissions result from combustion processes used to make energy, transport goods and people and other industrial operations. Our alternative futures could represent different types of power generation that could become more prevalent under different circumstances. For example, in one scenario solar or wind power would prevail leading to reductions in the burning of coal for power generation. In contrast, in another scenario coal use remains consistent with current usage but is subject to more emissions reductions. Another could presume significant inroads for electric vehicles. EPA will be considering this approach as another method for projecting a range of possibilities for the cost of attaining a tighter standard. This research will include a review of how best to characterize the likely adoption by 2020 (or similar target years) of new technologies (e.g., solar, wind and others unrelated to fossil fuel combustion, as well as more fuel-efficient vehicles), that are expected to have the ancillary benefit of facilitating compliance with new standards for criteria air pollutants. It will also include consideration of control measures that depend on behavioral change (such as congestion pricing) rather than simply the adoption of engineering controls.

The approach outlined above represents a significant amount of theoretical and applied analysis and the development of new methodologies for doing this analysis. Data supporting our cost approach is in the SO2 NAAQS RIA docket and we welcome ideas from the public on suggestions for analytical methods to estimate these future costs and plans to hopefully utilize portions of it in the proposed PM2.5 NAAQS RIA to be released with the rest of the material accompanying the standard.

Table 6.3 presents the extrapolated costs for each alternative standard analyzed. See Chapter 4 for a complete discussion of the air quality projections for these counties.

Table 6.3: Extrapolated Costs Estimated for the Alternative Standards (Millions of 2006$) [a, b]

	50 ppb	75 ppb	100 ppb
Total Extrapolated Costs ($10,000/ton):	$ 1,200	$ 330	$ 180
Total Extrapolated Costs ($15,000/ton):	**$ 1,800**	**$ 500**	**$ 260**
Total Extrapolated Costs ($20,000/ton):	$ 2,400	$ 670	$ 350

[a] All estimates rounded to two significant figures. As such, totals will not sum down columns.

[b] Estimates of extrapolated costs are assumed using a 7% discount rate. Given the fixed cost per ton approach used here, 3% discount rate estimates could not be calculated.

6.1.4 Monitoring Costs

The final amendments would revise the technical requirements for SO_2 monitoring sites; require the siting and operation of additional SO_2 ambient air monitors, and the reporting of the collected ambient monitoring data to EPA's Air Quality System (AQS). We have estimated the burden based on the monitoring requirements of this rule. Details of the burden estimate are contained in the information collection request (ICR) accompanying the final rule.[7] The ICR estimates annualized costs of a new monitoring network at approximately $15 million per year (2006 dollars).

6.1.5 Summary of Cost Estimates

Table 6.4 provides a summary of total costs to achieve the alternative standards in the year 2020, and this summary includes the sensitivity estimates. As mentioned previously, we use $15,000/ton as our primary estimate of the extrapolated costs on a per ton reduction basis, and $10,000/ton and $20,000/ton are used as sensitivities. Using that estimate, we find that the total annualized costs for the 75 ppb final standard in 2020 are $1.0 billion (2006$) using seven percent as the discount rate and applying the primary estimate of the extrapolated costs, and the costs for the other alternative standards range from $0.5 billion to $2.6 billion (2006$). The portion of these costs accounted for by identified controls ranges from 59 percent for the 50 ppb standard to 64 percent for the 100 ppb standard. Hence, the portion of these costs accounted for by extrapolated controls ranges from 41 percent for the 50 ppb standard to 36 percent for the 100 ppb standard.

Finally, Table 6.5 present the annual cost/ton for the identified controls by sector as applied for the alternative standards in 2020. For each alternative standard, the annual cost/ton for reductions from the non-EGU sector is the most expensive. For the 75 ppb final standard, reductions from non-EGUs occur at $2,400/ton while the annual cost/ton for EGU sector is $2,700/ton. All of these estimates are for reductions in 2020 in 2006 dollars and using a seven percent discount rate.

The significant difference between the costs of identified controls alone and the cost of achieving attainment (i.e. including both identified controls and emission reductions beyond identified controls) in this and other areas reflects the limited information available to EPA on

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[7] ICR 2358.01, May 2009.

the control measures that sources may implement. Although AirControlNET contains information on a large number of different point source controls, we would expect that State and local air quality managers would have access to additional information on the controls available to the most significant sources.

Table 6.4: Total Annual Costs for Alternative Standards (Millions of 2006$)[a, b]

		50 ppb	75 ppb	100 ppb
Identified Control Costs		$ 2,600	$ 960	$ 470
Monitoring Costs		$2.1	$2.1	$2.1
Extrapolated Costs	Fixed Cost ($10,000/ton)	$ 1,200	$ 330	$ 180
	[d]Fixed Cost ($15,000/ton)	**$ 1,800**	**$ 500**	**$ 260**
	Fixed Cost ($20,000/ton)	$ 2,400	$ 670	$ 350
Total Costs	Fixed Cost ($10,000/ton)	$ 3,800	$ 1,300	$ 650
	[d]Fixed Cost ($15,000/ton)	**$ 4,400**	**$ 1,500**	**$ 730**
	Fixed Cost ($20,000/ton)	$ 5,000	$ 1,600	$ 820

[a] All estimates rounded to two significant figures. As such, totals will not sum down columns.

[b] All estimates provided reflect the engineering cost of the identified control strategy analysis, incremental to a 2020.

[c] Values reflect a 7% discount rate.

[d] Our primary estimate of extrapolated costs is, as mentioned earlier in this RIA, based on a fixed annual cost of $15,000/ton. This estimate of extrapolated costs is incorporated into our estimate of total costs for the alternative standards.

Table 6.5: Annual Cost per Ton of Identified Controls applied for the Alternative Standards by Emissions Sector (2006$) [a, b]

Emissions Sector	50 ppb	75 ppb	100 ppb
NonEGU	$ 2,400	$ 2,700	$ 2,800
Area	$ 2,500	$ 2,200	$ 2,100
EGU	$ 2,700	$ 2,700	$ 2,800

[a] All estimates rounded to two significant figures. As such, totals will not sum down columns.

[b] All estimates provided reflect the engineering cost of the identified control strategy analysis, incremental to a 2020 baseline.

6.1.6 Technology Innovation and Regulatory Cost Estimates

There are many examples in which technological innovation and "learning by doing" have made it possible to achieve greater emissions reductions than had been feasible earlier, or have reduced the costs of emission control in relation to original estimates. Studies[8] have suggested that costs of some EPA programs have been less than originally estimated due in part to inadequate inability to predict and account for future technological innovation in regulatory impact analyses.

Constantly increasing marginal costs are likely to induce the type of innovation that would result in lower costs than estimated early in this chapter. Breakthrough technologies in control equipment could by 2020 result in a rightward shift in the marginal cost curve for such equipment (Figure 6.1)[9] as well as perhaps a decrease in its slope, reducing marginal costs per unit of abatement, and thus deviate from the assumption of a static marginal cost curve. In addition, elevated abatement costs may result in significant increases in the cost of production and would likely induce production efficiencies, in particular those related to energy inputs, which would lower emissions from the production side.

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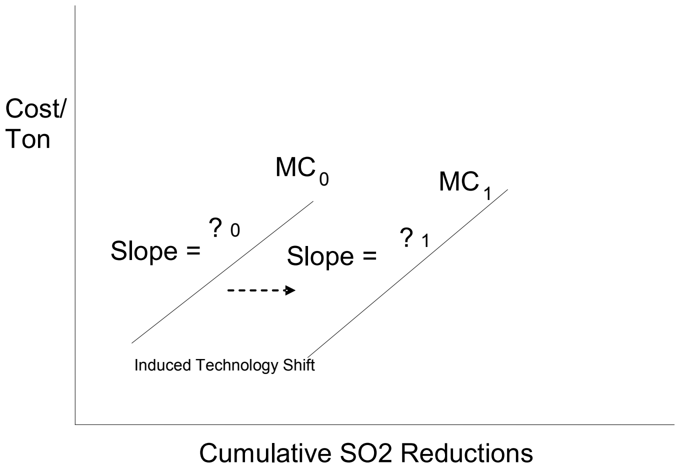
[8] Harrington et al. (2000) and previous studies cited by Harrington.
Harrington, W., R.D. Morgenstern, and P. Nelson. 2000. "On the Accuracy of Regulatory Cost Estimates." *Journal of Policy Analysis and Management* 19(2):297-322.

[9] Figure 6.1 shows a linear marginal abatement cost curve. It is possible that the shape of the marginal abatement cost curve is non-linear.

Figure 6.1: Technological Innovation Reflected by Marginal Cost Shift



6.1.6.1 Examples of Technological Advances in Pollution Control

There are numerous examples of low-emission technologies developed and/or commercialized over the past 15 or 20 years, such as:

- Selective catalytic reduction (SCR) and ultra-low NOx burners for NOx emissions
- Scrubbers which achieve 95% and even greater SO2 control on boilers
- Sophisticated new valve seals and leak detection equipment for refineries and chemical plans
- Low or zero VOC paints, consumer products and cleaning processes
- Chlorofluorocarbon (*CFC)* free air conditioners, refrigerators, and solvents
- Water and powder-based coatings to replace petroleum-based formulations
- Vehicles far cleaner than believed possible in the late 1980s due to improvements in evaporative controls, catalyst design and fuel control systems for light-duty vehicles; and treatment devices and retrofit technologies for heavy-duty engines

- Idle-reduction technologies for engines, including truck stop electrification efforts
- Market penetration of gas-electric hybrid vehicles, and clean fuels
- The development of retrofit technology to reduce emissions from in-use vehicles and non-road equipment

These technologies were not commercially available two decades ago, and some were not even in existence. Yet today, all of these technologies are on the market, and many are widely employed. Several are key components of major pollution control programs and most of the examples are discussed further below.

What is known as “learning by doing” or “learning curve impacts”, which is a concept distinct from technological innovation, has also made it possible to achieve greater emissions reductions than had been feasible earlier, or have reduced the costs of emission control in relation to original estimates. Learning curve impacts can be defined generally as the extent to which variable costs (of production and/or pollution control) decline as firms gain experience with a specific technology. Such impacts have been identified to occur in a number of studies conducted for various production processes. Impacts such as these would manifest themselves as a lowering of expected costs for operation of technologies in the future below what they may have been.

The magnitude of learning curve impacts on pollution control costs has been estimated for a variety of sectors as part of the cost analyses done for the Draft Direct Cost Report for the second EPA Section 812 Prospective Analysis of the Clean Air Act Amendments of 1990.[10] In that report, learning curve adjustments were included for those sectors and technologies for which learning curve data was available. A typical learning curve adjustment example is to reduce either capital or O&M costs by a certain percentage given a doubling of output from that sector or for that technology. In other words, capital or O&M costs will be reduced by some percentage for every doubling of output for the given sector or technology.

T.P. Wright, in 1936, was the first to characterize the relationship between increased productivity and cumulative production. He analyzed man-hours required to assemble successive airplane bodies. He suggested the relationship is a log linear function, since he observed a constant linear reduction in man-hours every time the total number of airplanes assembled was doubled. The relationship he devised between number assembled and assembly

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[10] E.H. Pechan and Associates and Industrial Economics, Direct Cost Estimates for the Clean Air Act Second Section 812 Prospective Analysis: Draft Report, prepared for U.S. EPA, Office of Air and Radiation, February 2007. Available at http://www.epa.gov/oar/sect812/mar07/direct_cost_draft.pdf.

time is called Wright's Equation (Gumerman and Marnay, 2004)[11]. This equation, shown below, has been shown to be widely applicable in manufacturing:

$$\text{Wright's Equation: } C_N = C_o * N^b,$$

Where:
N = cumulative production
C_N = cost to produce N^{th} unit of capacity
C_o = cost to produce the first unit
B = learning parameter = ln (1-LR)/ln(2), where
LR = learning by doing rate, or cost reduction per doubling of capacity or output.

The percentage adjustments to costs can range from 5 to 20 percent, depending on the sector and technology. Learning curve adjustments were prepared in a memo by IEc supplied to US EPA and applied for the mobile source sector (both onroad and nonroad) and for application of various EGU control technologies within the Draft Direct Cost Report.[12] Advice received from the SAB Advisory Council on Clean Air Compliance Analysis in June 2007 indicated an interest in expanding the treatment of learning curves to those portions of the cost analysis for which no learning curve impact data are currently available. Examples of these sectors are non-EGU point sources and area sources. The memo by IEc outlined various approaches by which learning curve impacts can be addressed for those sectors. The recommended learning curve impact adjustment for virtually every sector considered in the Draft Direct Cost Report is a 10% reduction in O&M costs for two doubling of cumulative output, with proxies such as cumulative fuel sales or cumulative emission reductions being used when output data was unavailable.

For this RIA, we do not have the necessary data for cumulative output, fuel sales, or emission reductions for all sectors included in our analysis in order to properly generate control costs that reflect learning curve impacts. Clearly, the effect of including these impacts would be to lower our estimates of costs for our control strategies in 2020, but we are not able to include such an analysis in this RIA.

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[11] Gumerman, Etan and Marnay, Chris. Learning and Cost Reductions for Generating Technologies in the National Energy Modeling System (NEMS), Ernest Orlando Lawrence Berkeley National Laboratory, University of California at Berkeley, Berkeley, CA. January 2004, LBNL-52559.

[12] Industrial Economics, Inc. Proposed Approach for Expanding the Treatment of Learning Curve Impacts for the Second Section 812 Prospective Analysis: Memorandum, prepared for U.S. EPA, Office of Air and Radiation, August 13, 2007.

6.1.6.2 Influence on Regulatory Cost Estimates

Studies indicate that it is not uncommon for pre-regulatory cost estimates to be higher than later estimates, in part because of inability to predict technological advances. Over longer time horizons the opportunity for technical advances is greater.

- *Multi-rule study:* Harrington et al. of Resources for the Future[13] conducted an analysis of the predicted and actual costs of 28 federal and state rules, including 21 issued by EPA and the Occupational Safety and Health Administration (OSHA), and found a tendency for predicted costs to overstate actual implementation costs. Costs were considered accurate if they fell within the analysis error bounds or if they fall within 25 percent (greater or less than) the predicted amount. They found that predicted total costs were overestimated for 14 of the 28 rules, while total costs were underestimated for only three rules. Differences can result because of quantity differences (e.g., overestimate of pollution reductions) or differences in per-unit costs (e.g., cost per unit of pollution reduction). Per-unit costs of regulations were overestimated in 14 cases, while they were underestimated in six cases. In the case of EPA rules, the agency overestimated per-unit costs for five regulations, underestimated them for four regulations (three of these were relatively small pesticide rules), and accurately estimated them for four. Based on examination of eight economic incentive rules, "for those rules that employed economic incentive mechanisms, overestimation of per-unit costs seems to be the norm," the study said. It is worth noting here, that the controls applied for this NAAQS do not use an economic incentive mechanism. In addition, Harrington also states that overestimation of total costs can be due to error in the quantity of emission reductions achieved, which would also cause the benefits to be overestimated.

Based on the case study results and existing literature, the authors identified technological innovation as one of five explanations of why predicted and actual regulatory cost estimates differ: "Most regulatory cost estimates ignore the possibility of technological innovation … Technical change is, after all, notoriously difficult to forecast … In numerous case studies actual compliance costs are lower than predicted because of unanticipated use of new technology."

It should be noted that many (though not all) of the EPA rules examined by Harrington had compliance dates of several years, which allowed a limited period for technical innovation.

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[13] Harrington, W., R.D. Morgenstern, and P. Nelson. 2000. "On the Accuracy of Regulatory Cost Estimates." *Journal of Policy Analysis and Management* 19(2):297-322.

- *Acid Rain SO2 Trading Program*: Recent cost estimates of the Acid Rain SO2 trading program by Resources for the Future (RFF) and MIT have been as much as 83 percent lower than originally projected by EPA.[14] As noted in the RIA for the Clean Air Interstate Rule, the ex ante numbers in 1989 were an overestimate in part because of the limitation of economic modeling to predict technological improvement of pollution controls and other compliance options such as fuel switching. The fuel switching from high-sulfur to low-sulfur coal was spurred by a reduction in rail transportation costs due to deregulation of rail rates during the 1990's Harrington et al. report that scrubbing turned out to be more efficient (95% removal vs. 80-85% removal) and more reliable (95% vs. 85% reliability) than expected, and that unanticipated opportunities arose to blend low and high sulfur coal in older boilers up to a 40/60 mixture, compared with the 5/95 mixture originally estimated.

Phase 2 Cost Estimates	
Ex ante estimates	\$2.7 to \$6.2 billion[a]
Ex post estimates	\$1.0 to \$1.4 billion

[a] 2010 Phase II cost estimate in 1995\$.

- *EPA Fuel Control Rules:* A 2002 study by EPA's Office of Transportation and Air Quality[15] examined EPA vehicle and fuels rules and found a general pattern that "all ex ante estimates tended to exceed actual price impacts, with the EPA estimates exceeding actual prices by the smallest amount." The paper notes that cost is not the same as price, but suggests that a comparison nonetheless can be instructive.[16] An example focusing on fuel rules is provided in Table 6.6:

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[14] Carlson, Curtis, Dallas R. Burtraw, Maureen, Cropper, and Karen L. Palmer. 2000. "Sulfur Dioxide Control by Electric Utilities: What Are the Gains from Trade?" *Journal of Political Economy* 108(#6):1292-1326.
Ellerman, Denny. January 2003. Ex Post Evaluation of Tradable Permits: The U.S. SO2 Cap-and-Trade Program. Massachusetts Institute of Technology Center for Energy and Environmental Policy Research.

[15] Anderson, J.F., and Sherwood, T., 2002. "Comparison of EPA and Other Estimates of Mobile Source Rule Costs to Actual Price Changes," Office of Transportation and Air Quality, U.S. Environmental Protection Agency. Technical Paper published by the Society of Automotive Engineers. SAE 2002-01-1980.

[16] The paper notes: "Cost is not the same as price. This simple statement reflects the fact that a lot happens between a producer's determination of manufacturing cost and its decisions about what the market will bear in terms of price change."

Table 6.6: Comparison of Inflation-Adjusted Estimated Costs and Actual Price Changes for EPA Fuel Control Rules[a]

	Inflation-adjusted Cost Estimates (c/gal)				Actual Price Changes (c/gal)
	EPA	DOE	API	Other	
Gasoline					
Phase 2 RVP Control (7.8 RVP—Summer) (1995$)	1.1	1.8		0.5	
Reformulated Gasoline Phase 1 (1997$)	3.1-5.1	3.4-4.1	8.2-14.0	7.4 (CRA)	2.2
Reformulated Gasoline Phase 2 (Summer) (2000$)	4.6-6.8	7.6-10.2	10.8-19.4	12	7.2 (5.1, when corrected to 5yr MTBE price)
30 ppm sulfur gasoline (Tier 2)	1.7-1.9	2.9-3.4	2.6	5.7 (NPRA), 3.1 (AIAM)	N/A
Diesel					
500 ppm sulfur highway diesel fuel (1997$)	1.9-2.4		3.3 (NPRA)	2.2	
15 ppm sulfur highway diesel fuel	4.5	4.2-6.0	6.2	4.2-6.1 (NPRA)	N/A

[a] Anderson, J.F., and Sherwood, T., 2002. “Comparison of EPA and Other Estimates of Mobile Source Rule Costs to Actual Price Changes,” Office of Transportation and Air Quality, U.S. Environmental Protection Agency. Technical Paper published by the Society of Automotive Engineers. SAE 2002-01-1980.

- Chlorofluorocarbon (*CFC) Phase-Out:* EPA used a combination of regulatory, market based (i.e., a cap-and-trade system among manufacturers), and voluntary approaches to phase out the most harmful ozone depleting substances. This was done more efficiently than either EPA or industry originally anticipated. The phaseout for Class I substances was implemented 4-6 years faster, included 13 more chemicals, and cost 30 percent less than was predicted at the time the 1990 Clean Air Act Amendments were enacted.[17]

The Harrington study states, “When the original cost analysis was performed for the CFC phase-out it was not anticipated that the hydrofluorocarbon HFC-134a could be substituted for CFC-12 in refrigeration. However, as Hammit[18] notes, ‘since 1991 most new U.S. automobile air conditioners have contained HFC-134a (a compound for which no commercial production technology was available in 1986) instead of CFC-12” (p.13). He cites a similar story for HCFRC-141b and 142b, which are currently substituting for CFC-11 in important foam-blowing applications.”

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[17] Holmstead, Jeffrey, 2002. “Testimony of Jeffrey Holmstead, Assistant Administrator, Office of Air and Radiation, U.S. Environmental Protection Agency, Before the Subcommittee on Energy and air Quality of the committee on Energy and Commerce, U.S. House of Representatives, May 1, 2002, p. 10.

[18] Hammit, J.K. (2000). “Are the costs of proposed environmental regulations overestimated? Evidence from the CFC phaseout.” *Environmental and Resource Economics*, 16(#3): 281-302.

Additional examples of decreasing costs of emissions controls include: SCR catalyst costs decreasing from \$11k-\$14k/m^3 in 1998 to \$3.5k-\$5k/m^3 in 2004, and improved low NOx burners reduced emissions by 50% from 1993-2003 while the associated capital cost dropped from \$25-\$38/kW to \$15/kW[19]. Also, FGD scrubber capital costs have been estimated to have decreased by more than 50 percent from 1976 to 2005, and the operating and maintenance (O&M) costs decreased by more than 50% from 1982 to 2005. Many process improvements contributed to lowering the capital costs, especially improved understanding and control of process chemistry, improved materials of construction, simplified absorber designs, and other factors that improved reliability.[20]

We cannot estimate the precise interplay between EPA regulation and technology improvement, but it is clear that a *priori* cost estimation often results in overestimation of costs because changes in technology (whatever the cause) make less costly control possible.

6.2 Economic Impacts

The assessment of economic impacts in Table 6.7 was conducted based on those source categories which are assumed in this analysis to become controlled. The impacts presented here are a comparison of the control costs to the revenues for industries affected by control strategies applied for the 75 ppb final standard. Control costs are allocated to specific source categories by North American Industry Classification System (NAICS) code.

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[19] ICF Consulting. October 2005. The Clean Air Act Amendment: Spurring Innovation and Growth While Cleaning the Air. Washington, DC. Available at http://www.icfi.com/Markets/Environment/doc_files/caaa-success.pdf.

[20] Yeh, Sonia and Rubin, Edward. February 2007. "Incorporating Technological Learning in the Coal Utility Environmental Cost (CUECost) Model: Estimating the Future Cost Trends of SO_2, NOx, and Mercury Control Technologies." Prepared for ARCADIS Geraghty and Miller, Research Triangle Park, NC 27711. Available at http://steps.ucdavis.edu/People/slyeh/syeh-resources/Drft%20Fnl%20Rpt%20Lrng%20for%20CUECost_v3.pdf.

Table 6.7: Identified Cost/Revenue Ratios by Affected Industry for Illustrative Control Strategy for the Final SO2 Standard (75 ppb) in 2020 (Millions of 2006$)[a, b, c]

NAICS Code	Industry Description	3% Discount Rate[d]	7% Discount Rate	Industry Revenue in 2007[e]	Cost/Revenue Ratio
2211	Electric Power Generation, Transmission and Distribution	699	699	440,000	0.16%
311	Food Manufacturing	55	19.9	589,000	<0.01%
312	Beverage and Tobacco Product Manufacturing	1.3	7.0	128,000	<0.01%
322	Paper Manufacturing	$143	$31.2	$170,000	< 0.01%
324	Petroleum and Coal Products Manufacturing	$245	$39.5	$590,000	< 0.01%
325	Chemical Manufacturing	$12.8	$12.8	$720,000	< 0.01%
326	Plastics and Rubber Products Manufacturing	6.2	6.2	211,000	<0.01%
327	Nonmetallic Mineral Product Manufacturing	266	43.5	128,000	<0.01%
331	Primary Metal Manufacturing	$	$43.6	$250,000	< 0.01%
332	Fabricated metal product manufacturing	0.4	0.4	344,000	< 0.01%
333	Machinery manufacturing	3.0	3.0	19,700	< 0.01%
336	Transportation equipment manufacturing	2.9	0.8	737,000	< 0.01%
611	Educational services	137	51.9	47,000	0.13%

[a] All estimates rounded to two significant figures. As such, totals will not sum down columns.

[b] All estimates provided reflect the engineering cost of the identified control strategy analysis, incremental to a 2020 baseline.

[c] NAICS codes were unavailable for area source controls. These controls account for less than 2% of the total identified control strategy costs.

[d] Total annualized costs were calculated using a 3% discount rate for controls which had a capital component and where equipment life values were available. For the identified control strategy, data for calculating annualized costs at a 3% discount was available for point sources. Therefore, the total annualized identified control cost value presented in this referenced cell is an aggregation of engineering costs at 3% and 7% discount rate.

[e] Source: U.S. Census Bureau 2007 Economic Census. Industry-level data on revenues can be found at http://factfinder.census.gov/servlet/IBQTable?_bm=y&-fds_name=EC0700A1&-_skip=0&-ds_name=EC0700A1&-_lang=en.

[f] No data on budget or revenues for this NAICS code is included in the 2007 Economic Census.

6.3 Energy Impacts

This section summarizes the energy consumption impacts associated with control strategies applied for the final SO_2 NAAQS of 75 ppb. The SO_2 NAAQS revisions do not constitute a "significant energy action" as defined in Executive Order 13211; this information merely represents impacts of the illustrative control strategy applied in the RIA. The rule does not prescribe specific control strategies by which these ambient standards will be met. Such strategies will be developed by States on a case-by-case basis, and EPA cannot predict whether the control options selected by States will include regulations on energy suppliers, distributors, or users. Thus, EPA concludes that this rule is not likely to have any adverse energy effects as defined in Executive Order 13211.

For this RIA, implementation of the control measures needed for attainment with the alternative standards will likely lead to increased energy consumption among SO_2 emitting facilities. In addition, because the energy consumption and impacts on various energy markets associated with emission reductions beyond identified controls is uncertain, we only consider the energy impacts associated with identified controls.

With respect to energy supply and prices, the analysis in Table 6.7 suggests that at the electric power industry level, the annualized costs associated with the illustrative control strategy for the final standard (75 ppb) represent only about 0.16 percent of its revenues in 2020. In addition, for the other industries affected under the 75 ppb standard, no other industry has annualized costs of more than 0.13 percent of its revenues. As a result we can conclude that impacts to supply and electricity price are small

6.4 Limitations and Uncertainties Associated with Engineering Cost Estimates

- EPA bases its estimates of emissions control costs on the best available information from engineering studies of air pollution controls and has developed a reliable modeling framework for analyzing the cost, emissions changes, and other impacts of regulatory controls. The annualized cost estimates of the private compliance costs are meant to show the increase in production (engineering) costs to the various affected sectors in our control strategy analyses. To estimate these annualized costs, EPA uses conventional and widely-accepted approaches that are commonplace for estimating engineering costs in annual terms. However, our engineering cost analysis is subject to uncertainties and limitations.

- One of these limitations is that we do not have sufficient information for all of our known control measures to calculate cost estimates that vary with an interest rate. We are able to calculate annualized costs at an interest rate other than 7% (e.g., 3% interest rate) where there is sufficient information—available capital cost data, and equipment life—to annualize the costs for individual control measures. For the vast majority of nonEGU point source control measures, we do have sufficient capital cost and equipment life data for individual control measures to prepare annualized capital costs using the standard capital recovery factor. Hence, we are able to provide annualized cost estimates at different interest rates for the point source control measures.

- For area source control measures, the engineering cost information is available only in annualized cost/ton terms. We have extremely limited capital cost and equipment life data for area source control measures. We know that these annualized cost/ton estimates reflect an interest rate of 7% because these estimates are typically products of technical memos and reports prepared as part of rules issued by EPA over the last 10 years or so, and the costs estimated in these reports have followed the policy provided in OMB Circular A-4 that recommends the use of 7% as the interest rate for annualizing regulatory costs. Capital cost information for these area source controls, however, is often limited since these measures are often not the traditional add-on controls where the capital cost is well known and convenient to estimate. The limited availability of useful capital cost data for such control measures has led to our use of annualized cost/ton estimates to represent the engineering costs of these controls in our cost tools and hence in this RIA.

- There are some unquantified costs that are not adequately captured in this illustrative analysis. These costs include the costs of federal and State administration of control programs, which we believe are less than the alternative of States developing approvable SIPs, securing EPA approval of those SIPs, and Federal/State enforcement. The analysis also did not consider transactional costs and/or effects on labor supply in the illustrative analysis.

Chapter 7: Estimates of Costs and Benefits

Synopsis

As discussed above, this RIA analyzes alternative primary standards of 50 parts per billion (ppb), 75 ppb, and 100 ppb. Our assessment of the lower bound SO_2 target NAAQS includes several key elements, including specification of baseline SO_2 emissions and concentrations; development of illustrative control strategies to attain the standard in 2020; and analyses of the control costs and health benefits of reaching the various alternative standards. We also note that because it was not possible, in this analysis, to bring all areas into attainment with the selected standard of 75 ppb in all areas using only identified controls, EPA conducted a second step in the analysis, and estimated the cost of unspecified emission reductions needed to attain the alternative primary NAAQS.

This analysis does not estimate the projected attainment status of areas of the country other than those counties currently served by one of the approximately 488 monitors in the current network. It is important to note that the rule would require a monitoring network wholly comprised of monitors sited at locations of expected maximum hourly concentrations. Only about one third of the existing SO_2 network may be source-oriented and/or in the locations of maximum concentration required by the proposed rule because the current network is focused on population areas and community-wide ambient levels of SO_2. Actual monitored levels using the new monitoring network may be higher than levels measured using the existing network. We recognize that once a network of monitors located at maximum-concentration is put in place, more areas could find themselves exceeding the new SO_2 NAAQS. However for this RIA analysis, we lack sufficient data to predict which counties might exceed the new NAAQS after implementation of the new monitoring network. Therefore we lack a credible analytic path to estimating costs and benefits for such a future scenario.

7.1 Benefits and Costs

We estimated the benefits and costs for four alternative SO_2 NAAQS levels: 50 ppb, 75 ppb, and 100 ppb (99th percentile). These costs and benefits are associated with an incremental difference in ambient concentrations between a baseline scenario and a pollution control strategy. As indicated above and in Chapter 4, several areas of the country may not be able to attain some alternative standard using known pollution control methods. Because some areas require substantial emission reductions from unknown sources to attain the various standards, the results are very sensitive to assuming full attainment. For this reason, we provide the full attainment and the partial attainment results for both benefits and costs.

Costs

Our analysis of the costs associated with the range of alternative NAAQS focuses on SO_2 emission controls for electric generating units (EGU) and nonEGU stationary and area sources. EGU, nonEGU and area source controls largely include measures from the Control Strategy Tool (CoST), and the AirControlNET control technology database. For these sources, we estimated costs based on the cost equations included in AirControlNET.

As indicated in the above discussion on illustrative control strategies, implementation of the SO_2 control measures identified from AirControlNET and other sources does not result in attainment with the selected NAAQS in several areas. In these areas, additional unspecified emission reductions might be necessary to reach some alternative standard levels. In order to bring these monitor areas into attainment, we calculated controls costs using a fixed cost per ton approach similar to that used in the ozone RIA analysis. We recognize that a single fixed cost of control of $15,000 per ton of emissions reductions does not account for the significant emissions cuts that are necessary in some areas, and so its use provides an estimate that is likely to differ from actual future costs.

Benefits

EPA estimated the monetized human health benefits of reducing cases of morbidity among populations exposed to SO_2 and cases of morbidity and premature mortality among populations exposed to $PM_{2.5}$ in 2020 for the selected standard and alternative standard levels in 2006$. Because SO_2 is also a precursor to $PM_{2.5,}$ reducing SO_2 emissions in the projected non-attainment areas will also reduce $PM_{2.5}$ formation, human exposure and the incidence of $PM_{2.5}$-related health effects. For the selected SO_2 standard at 75 ppb (99th percentile, daily 1-hour maximum), the total monetized benefits would be $15 to $37 billion at a 3% discount rate and $14 to $33 billion at a 7% discount rate. For an SO_2 standard at 50 ppb, the total monetized benefits would be $34 to $83 billion at a 3% discount rate and $31 to $75 billion at a 7% discount rate. For an SO_2 standard at 100 ppb, the total monetized benefits would be $7.4 to $18 billion at a 3% discount rate and $6.7 to $16 billion at a 7% discount rate.

These estimates reflect EPA's most current interpretation of the scientific literature and are consistent with the methodology used for the proposal RIA. These benefits are incremental to an air quality baseline that reflects attainment with the 2008 ozone and 2006 $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS). More than 99% of the total dollar benefits are attributable to reductions in $PM_{2.5}$ exposure resulting from SO_2 emission reductions. Higher or lower estimates of benefits are possible using other assumptions; examples of this are provided in Figure 5.1 for the selected standard of 75 ppb. Methodological limitations prevented EPA from quantifying the impacts to, or monetizing the benefits from several important benefit categories, including ecosystem effects from sulfur deposition, improvements in visibility, and materials damage. Other direct benefits from reduced SO_2 exposure have not been quantified, including reductions in premature mortality.

When estimating the SO_2- and $PM_{2.5}$-related human health benefits and compliance costs in Table 7.1 below, EPA applied methods and assumptions consistent with the state-of-the-science for human health impact assessment, economics and air quality analysis. EPA applied its best professional judgment in performing this analysis and believes that these estimates provide a reasonable indication of the expected benefits and costs to the nation of the selected SO_2 standard and alternatives considered by the Agency. The Regulatory Impacts Analysis (RIA) available in the docket describes in detail the empirical basis for EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below.

EPA's 2009 Integrated Science Assessment for Particulate Matter concluded, based on the scientific literature, that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship. Nonetheless, consistent with historical practice and our commitment to characterizing the uncertainty in our benefits estimates, EPA has included a sensitivity analysis with an assumed threshold in the PM-mortality health impact function in the RIA. EPA has included a sensitivity analysis in the RIA to help inform our understanding of the health benefits which can be achieved at lower air quality concentration levels. While the primary estimate and the sensitivity analysis are not directly comparable, due to differences in population data and use of different analysis years, as well as the difference in the assumption of a threshold in the sensitivity analysis, comparison of the two results provide a rough sense of the proportion of the health benefits that occur at lower $PM_{2.5}$ air quality levels. Using a threshold of 10 $\mu g/m^3$ is an arbitrary choice (EPA could have assumed 6, 8, or 12 µg/m3 for the sensitivity analysis). Assuming a threshold of 10 $\mu g/m^3$, the sensitivity analysis shows that roughly one-third of the benefits occur at air quality levels below that threshold. Because the primary estimates reflect EPA’s current methods and data, EPA notes that caution should be exercised when comparing the results of the primary and sensitivity analyses. EPA appreciates the value of sensitivity analyses in highlighting the uncertainty in the benefits estimates and will continue to work to refine these analyses, particularly in those instances in which air quality modeling data are available.

Table 7.1 presents total national primary estimates of costs and benefits for a 3% discount rate and a 7% discount rate. The net benefits were calculated by subtracting the total cost estimate from the two estimates of total benefits. As indicated above, implementation of the SO_2 control measures identified from AirControlNET and other sources does not result in attainment with the all target NAAQS levels in several areas. In these areas, additional unspecified emission reductions might be necessary to reach some alternative standard levels. The first part of the table, labeled *Partial attainment (known controls)*, shows only those benefits and costs from control measures we were able to identify. The second part of the table, labeled U*nidentified Controls*, shows only additional benefits and costs resulting from unidentified controls. The third part of the table, labeled *Full attainment*, shows total benefits and costs resulting from both identified and unidentified controls. It is important to emphasize that we were able to identify control measures for a significant portion of attainment for many of those counties that would not fully attain the target NAAQS level with identified controls. Note also that in addition to separating full and partial attainment, the table also separates the portion of benefits associated with reduced SO_2 exposure (i.e., SO_2 benefits) from the additional benefits associated with reducing SO_2 emissions, which are precursors to $PM_{2.5}$ formation – (i.e., the $PM_{2.5}$ co-benefits). For instance, for the selected standard of 75 ppb, $2.2 million in benefits are associated with reduced SO_2 exposure while $15 billion to $37 billion are associated with reduced $PM_{2.5}$ exposure.

Table 7.1: Monetized Benefits and Costs to Attain Alternate Standard Levels in 2020 (millions of 2006$) [a]

		# Counties Fully Controlled	Discount Rate	Monetized SO_2 Benefits	Monetized $PM_{2.5}$ Co-Benefits [c,d]	Costs	Net Benefits
Partial Attainment (identified controls)	50 ppb	40	3%	-[b]	\$30,000 to \$74,000	\$2,600	\$27,000 to \$71,000
			7%		\$28,000 to \$67,000		\$25,000 to \$64,000
	75 ppb	20	3%	-[b]	\$14,000 to \$35,000	\$960	\$13,000 to \$34,000
			7%		\$13,000 to \$31,000		\$12,000 to \$30,000
	100 ppb	6	3%	-[b]	\$6,900 to \$17,000	\$470	\$6,400 to \$17,000
			7%		\$6,200 to \$15,000		\$5,700 to \$15,000
Unidentified Controls	50 ppb	16	3%	-[b]	\$4,000 to \$9,000	\$1,800	\$2,200 to \$7,200
			7%		\$3,000 to \$8,000		\$1,200 to \$6,200
	75 ppb	4	3%	-[b]	\$1,000 to \$3,000	\$500	\$500 to \$1,500
			7%		\$1,000 to \$3,000		\$500 to \$2,500
	100 ppb	3	3%	-[b]	\$500 to \$1,000	\$260	\$240 to \$740
			7%		\$500 to \$1,000		\$240 to \$740
Full Attainment	50 ppb	56	3%	\$8.50	\$34,000 to \$83,000	\$4,400	\$30,000 to \$79,000
			7%		\$31,000 to \$75,000		\$27,000 to \$71,000
	75 ppb	24	3%	\$2.20	\$15,000 to \$37,000	\$1,500	\$14,000 to \$36,000
			7%		\$14,000 to \$34,000		\$13,000 to \$33,000
	100 ppb	9	3%	\$0.60	\$7,400 to \$18,000	\$730	\$6,700 to \$17,000
			7%		\$6,700 to \$16,000		\$6,000 to \$15,000

[a] Estimates have been rounded to two significant figures and therefore summation may not match table estimates.

[b] The approach used to simulate air quality changes for SO_2 did not provide the data needed to distinguish partial attainment benefits from full attainment benefits from reduced SO_2 exposure. Therefore, a portion of the SO_2 benefits is attributable to the known controls and a portion of the SO_2 benefits are attributable to the unidentified controls. Because all SO_2-related benefits are short-term effects, the results are identical for all discount rates.

[c] Benefits are shown as a range from Pope et al (2002) to Laden et al. (2006). Monetized benefits do not include unquantified benefits, such as other health effects, reduced sulfur deposition, or improvements in visibility.

[d] These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. Reductions in SO_2 emissions from multiple sectors to meet the SO_2 NAAQS would primarily reduce the sulfate fraction of $PM_{2.5}$. Because this rule targets a specific particle precursor (i.e., SO_2), this introduces some uncertainty into the results of the analysis.

7.2 Discussion of Uncertainties and Limitations

Air Quality, Emissions, and Control Strategies

The estimates of emission reductions associated with the control strategies described above are subject to important limitations and uncertainties. We summarize these limitations as follows:

- *Actual State Implementation Plans May Differ from our Simulation*: In order to reach attainment with the proposed NAAQS, each state will develop its own implementation plan implementing a combination of emissions controls that may differ from those simulated in this analysis. This analysis therefore represents an approximation of the emissions reductions that would be required to reach attainment and should not be treated as a precise estimate.

- *Use of Existing CMAQ Model Runs*: This analysis represents a screening level analysis. We did not conduct new regional scale modeling specifically targets to SO_2; instead we relied upon impact ratios developed from model runs used in the analysis underlying the $PM_{2.5}$ NAAQS.

- *Unidentified controls*: We have limited information on available controls for some of the monitor areas included in this analysis. For a number of small non-EGU and area sources, there is little or no information available on SO_2 controls.

Costs

- We do not have sufficient information for all of our known control measures to calculate cost estimates that vary with an interest rate. We are able to calculate annualized costs at an interest rate other than 7% (e.g., 3% interest rate) where there is sufficient information—available capital cost data, and equipment life—to annualize the costs for individual control measures. For the vast majority of nonEGU point source control measures, we do have sufficient capital cost and equipment life data for individual control measures to prepare annualized capital costs using the standard capital recovery factor. Hence, we are able to provide annualized cost estimates at different interest rates for the point source control measures.

- There are some unquantified costs that are not adequately captured in this illustrative analysis. These costs include the costs of federal and State administration of control programs, which we believe are less than the alternative of States developing approvable SIPs, securing EPA approval of those SIPs, and Federal/State enforcement. Additionally, control measure costs referred to as “no cost” may require limited government agency resources for administration and oversight of the program not included in this analysis; those costs are generally outweighed by the saving to the industrial, commercial, or private sector. The Agency also did not consider transactional costs and/or effects on labor supply in the illustrative analysis.

Benefits

Although we strive to incorporate as many quantitative assessments of uncertainty, there are several aspects for which we are only able to address qualitatively. These aspects are important factors to consider when evaluating the relative benefits of the attainment strategies for each of the alternative standards:

1. The 12 km CMAQ grid, which is the air quality modeling resolution, may be too coarse to accurately estimate the potential near-field health benefits of reducing SO_2 emissions. These uncertainties may under- or over-estimate benefits.
2. The interpolation techniques used to estimate the full attainment benefits of the alternative standards contributed some uncertainty to the analysis. The great majority of benefits estimated for the various standard alternatives were derived through interpolation. As noted previously in this chapter, these benefits are likely to be more uncertain than if we had modeled the air quality scenario for both SO_2 and $PM_{2.5}$. In general, the VNA interpolation approach will under-estimate benefits because it does not account for the broader spatial distribution of air quality changes that may occur due to the implementation of a regional emission control program.
3. There are many uncertainties associated with the health impact functions used in this modeling effort. These include: within study variability (the precision with which a given study estimates the relationship between air quality changes and health effects); across study variation (different published studies of the same pollutant/health effect relationship typically do not report identical findings and in some instances the differences are substantial); the application of C-R functions nationwide (does not account for any relationship between region and health effect, to the extent that such a relationship exists); extrapolation of impact functions across population (we assumed that certain health impact functions applied to age ranges broader than that considered in the original epidemiological study); and various uncertainties in the C-R function, including causality and thresholds. These uncertainties may under- or over-estimate benefits.
4. Co-pollutants present in the ambient air may have contributed to the health effects attributed to SO_2 in single pollutant models. Risks attributed to SO_2 might be overestimated where concentration-response functions are based on single pollutant models. If co-pollutants are highly correlated with SO_2, their inclusion in an SO_2 health effects model can lead to misleading conclusions in identifying a specific causal pollutant. Because this collinearity exists, many of the studies reported statistically insignificant effect estimates for both SO_2 and the co-pollutants; this is due in part to the loss of statistical power as these models control for co-pollutants. Where available, we

have selected multipollutant effect estimates to control for the potential confounding effects of co-pollutants; these include NYDOH (2006), Schwartz et al. (1994) and O'Connor et al. (2008). The remaining studies include single pollutant models.

5. This analysis is for the year 2020, and projecting key variables introduces uncertainty. Inherent in any analysis of future regulatory programs are uncertainties in projecting atmospheric conditions and source level emissions, as well as population, health baselines, incomes, technology, and other factors.
6. This analysis omits certain unquantified effects due to lack of data, time and resources. These unquantified endpoints include other health effects, ecosystem effects, and visibility. EPA will continue to evaluate new methods and models and select those most appropriate for estimating the benefits of reductions in air pollution. Enhanced collaboration between air quality modelers, epidemiologists, toxicologists, ecologists, and economists should result in a more tightly integrated analytical framework for measuring benefits of air pollution policies.
7. $PM_{2.5}$ co-benefits represent a substantial proportion of total monetized benefits (over 99% of total monetized benefits), and these estimates are subject to a number of assumptions and uncertainties.
    a. $PM_{2.5}$ co-benefits were derived through benefit per-ton estimates, which do not reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors that might lead to an over-estimate or under-estimate of the actual benefits of controlling directly emitted fine particulates.
    b. We assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because $PM_{2.5}$ produced via transported precursors emitted from EGUs may differ significantly from direct $PM_{2.5}$ released from diesel engines and other industrial sources, but no clear scientific grounds exist for supporting differential effects estimates by particle type.
    c. We assume that the health impact function for fine particles is linear within the range of ambient concentrations under consideration. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of $PM_{2.5,}$ including both regions that are in attainment with fine particle standard and those that do not meet the standard down to the lowest modeled concentrations.
    d. To characterize the uncertainty in the relationship between $PM_{2.5}$ and premature mortality (which typically accounts for 85% to 95% of total monetized benefits), we include a set of twelve estimates based on results of the expert elicitation study in addition to our core estimates. Even these multiple characterizations

> omit the uncertainty in air quality estimates, baseline incidence rates, populations exposed and transferability of the effect estimate to diverse locations. As a result, the reported confidence intervals and range of estimates give an incomplete picture about the overall uncertainty in the $PM_{2.5}$ estimates. This information should be interpreted within the context of the larger uncertainty surrounding the entire analysis. For more information on the uncertainties associated with $PM_{2.5}$ co-benefits, please consult the $PM_{2.5}$ NAAQS RIA (Table 5.5).

While the monetized benefits of reduced SO_2 exposure appear small when compared to the monetized benefits of reduced $PM_{2.5}$ exposure, readers should not necessarily infer that the total monetized benefits of attaining a new SO_2 standard are minimal. For this rule, the monetized $PM_{2.5}$ co-benefits represent over 99% of the total monetized benefits. This result is consistent with other recent RIAs, where the $PM_{2.5}$ co-benefits represent a large proportion of total monetized benefits. This result is amplified in this RIA by the decision not to quantify SO_2-related premature mortality and other morbidity endpoints due to the uncertainties associated with estimating those endpoints. Studies have shown that there is a relationship between SO_2 exposure and premature mortality, but that relationship is limited by potential confounding. Because premature mortality generally comprises over 90% of the total monetized benefits, this decision may substantially underestimate the monetized health benefits of reduced SO_2 exposure.

In addition, we were unable to quantify the benefits from several welfare benefit categories. We lacked the necessary air quality data to quantify the benefits from improvements in visibility from reducing light-scattering particles. Previous RIAs for ozone (U.S. EPA, 2008a) and $PM_{2.5}$ (U.S. EPA, 2006a) indicate that visibility is an important benefit category, and previous efforts to monetize those benefits have only included a subset of visibility benefits, excluding benefits in urban areas and many national and state parks. Even this subset accounted for up to 5% of total monetized benefits in the Ozone NAAQS RIA (U.S. EPA, 2008a).

We were also unable to quantify the ecosystem benefits of reduced sulfur deposition because we lacked the necessary air quality data, and the methodology to estimate ecosystem benefits is still being developed. Previous assessments (U.S. EPA, 1999; U.S. EPA, 2005; U.S. EPA, 2009e) indicate that ecosystem benefits are also an important benefits category, but those efforts were only able to monetize a tiny subset of ecosystem benefits in specific geographic locations, such as recreational fishing effects from lake acidification in the Adirondacks. We were also unable to quantify the benefits of decreased mercury methylation from sulfate deposition. Quantifying the relationship between sulfate and mercury methylation in natural settings is difficult, but some studies have shown that decreasing sulfate deposition can also decrease methylmercury.

Chapter 8: Statutory and Executive Order Reviews

1.0 Executive Order 12866: Regulatory Planning and Review

Under section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action. In addition, EPA prepared a Regulatory Impact Analysis (RIA) of the potential costs and benefits associated with this action. However, the CAA and judicial decisions make clear that the economic and technical feasibility of attaining the national ambient standards cannot be considered in setting or revising NAAQS, although such factors may be considered in the development of State implementation plans to implement the standards. Accordingly, although an RIA has been prepared, the results of the RIA have not been considered by EPA in developing this final rule.

2.0 Paperwork Reduction Act

The information collection requirements in this final rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The Information Collection Request (ICR) document prepared by EPA for these proposed revisions to part 58 has been assigned EPA ICR number 2370.01.

The information collected under 40 CFR part 53 (e.g., test results, monitoring records, instruction manual, and other associated information) is needed to determine whether a candidate method intended for use in determining attainment of the NAAQS in 40 CFR part 50 will meet the design, performance, and/or comparability requirements for designation as a Federal reference method (FRM) or Federal equivalent method (FEM). We do not expect the number of FRM or FEM determinations to increase over the number that is currently used to estimate burden associated with SO_2 FRM/FEM determinations provided in the current ICR for 40 CFR part 53 (EPA ICR numbers 2370.01). As such, no change in the burden estimate for 40 CFR part 53 has been made as part of this rulemaking.

The information collected and reported under 40 CFR part 58 is needed to determine compliance with the NAAQS, to characterize air quality and associated health impacts, to develop emissions control strategies, and to measure progress for the air pollution program. The amendments would revise the technical requirements for SO_2 monitoring sites, require the siting and operation of additional SO_2 ambient air monitors, and the reporting of the collected ambient SO_2 monitoring data to EPA's Air Quality System (AQS). This Information Collection is estimated to involve 102 respondents for a total approximate cost of $15,203,762 (total capital, and labor and non-labor operation and maintenance) and a total burden of 207,662 hours. The labor costs associated with these hours is $11,130,409. Included in the $15,203,762 total are other costs of non-labor operations and maintenance of $1,104,377 and equipment and contract costs of $2,968,975. In addition to the costs at the State and local air quality management agencies, there is a burden to EPA of total of 14,749 hours and $1,060,621. Burden is defined at 5 CFR 1320.3(b). State, local, and tribal entities are eligible for State assistance grants provided by the Federal government under the CAA which can be used for monitors and related activities.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

3.0 Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, small entity is defined as: (1) a small business that is a small industrial entity as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This final rule will not impose any requirements on small entities. Rather, this rule establishes national standards for allowable concentrations of SO_2 in ambient air as required by section 109 of the CAA. *American Trucking Ass'ns v. EPA,* 175 F. 3d 1027, 1044-45 (D.C. Cir. 1999) (NAAQS do not have significant impacts upon small entities because NAAQS themselves impose no regulations upon small entities). Similarly, the amendments to 40 CFR Part 58 address the requirements for States to collect information and report compliance with the NAAQS and will not impose any requirements on small entities.

4.0 Unfunded Mandates Reform Act

This action is not subject to the requirements of sections 202 and 205 of the UMRA. EPA has determined that this proposed rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. The revisions to the SO_2 NAAQS impose no enforceable duty on any State, local or Tribal governments or the private sector. The expected costs associated with the monitoring requirements are described in EPA's ICR document, but those costs are not expected to exceed $100 million in the aggregate for any year. Furthermore, as indicated previously, in setting a NAAQS, EPA cannot consider the economic or technological feasibility of attaining ambient air quality standards. Because the CAA prohibits EPA from considering the types of estimates and assessments described in section 202 when setting the NAAQS, the UMRA does not require EPA to prepare a written statement under section 202 for the revisions to the SO_2 NAAQS.

With regard to implementation guidance, the CAA imposes the obligation for States to submit SIPs to implement the SO_2 NAAQS. In this final rule, EPA is merely providing an interpretation of those requirements. However, even if this rule did establish an independent obligation for States to submit SIPs, it is questionable whether an obligation to submit a SIP revision would constitute a Federal mandate in any case. The obligation for a State to submit a SIP that arises out of section 110 and section 191 of the CAA is not legally enforceable by a court of law, and at most is a condition for continued receipt of highway funds. Therefore, it is possible to view an action requiring such a submittal as not creating any enforceable duty within the meaning of U.S.C. 658 for purposes of the UMRA. Even if it did, the duty could be viewed as falling within the exception for a condition of Federal assistance under U.S.C. 658.

EPA has determined that this final rule contains no regulatory requirements that might significantly or uniquely affect small governments because it imposes no enforceable duty on any small governments. Therefore, the rule is not subject to the requirements of section 203 of the UMRA.

5.0 Executive Order 13132: Federalism

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The rule does not alter the relationship between the Federal government and the States regarding the establishment and implementation of air quality improvement programs as codified in the CAA. Under section 109 of the CAA, EPA is mandated to establish NAAQS; however, CAA section 116 preserves the rights of States to establish more stringent requirements if deemed necessary by a State. Furthermore, this rule does not impact CAA section 107 which establishes that the States have primary responsibility for implementation of the NAAQS. Finally, as noted in section E (above) on UMRA, this rule does not impose significant costs on State, local, or tribal governments or the private sector. Thus, Executive Order 13132 does not apply to this rule.

6.0 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Executive Order 13175, entitled “Consultation and Coordination with Indian Tribal Governments” (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure “meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.” This final rule does not have tribal implications, as specified in Executive Order 13175. It does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and tribes. The rule does not alter the relationship between the Federal government and tribes as established in the CAA and the TAR. Under section 109 of the CAA, EPA is mandated to establish NAAQS; however, this rule does not infringe existing tribal authorities to regulate air quality under their own programs or under programs submitted to EPA for approval. Furthermore, this rule does not affect the flexibility afforded to tribes in seeking to implement CAA programs consistent with the TAR, nor does it impose any new obligation on tribes to adopt or implement any NAAQS. Finally, as noted in section E (above) on UMRA, this rule does not impose significant costs on tribal governments. Thus, Executive Order 13175 does not apply to this rule.

7.0 Executive Order 13045: Protection of Children from Environmental Health & Safety Risks

This action is subject to Executive Order (62 FR 19885, April 23, 1997) because it is an economically significant regulatory action as defined by Executive Order 12866, and we believe that the environmental health risk addressed by this action has a disproportionate effect on children. This final rule will establish uniform national ambient air quality standards for SO_2; these standards are designed to protect public health with an adequate margin of safety, as required by CAA section 109. The protection offered by these standards may be especially important for asthmatics, including asthmatic children, because respiratory effects in asthmatics are among the most sensitive health endpoints for SO_2 exposure. Because asthmatic children are considered a sensitive population, we have evaluated the potential health effects of exposure to SO_2 pollution among asthmatic children. These effects and the size of the population affected are discussed in chapters 3 and 4 of the ISA; chapters 3, 4, 7, 8, 9 of the REA, and sections II.A through II.E of the preamble.

8.0 Executive Order 13211: Actions that Significantly Affect Energy Supply, Distribution or Use

This rule is not a “significant energy action” as defined in Executive Order 13211, “Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use” (66 FR 28355; May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The purpose of this rule is to establish revised NAAQS for SO_2. The rule does not prescribe specific control strategies by which these ambient standards will be met. Such strategies will be developed by States on a case-by-case basis, and EPA cannot predict whether the control options selected by States will include regulations on energy suppliers, distributors, or users. Thus, EPA concludes that this rule is not likely to have any adverse energy effects.

9.0 National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104-113, section 12(d) (15 U.S.C. 27) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves technical standards with regard to ambient monitoring of SO_2. The use of this voluntary consensus standard would be impractical because the analysis method does not provide for the method detection limits necessary to adequately characterize ambient SO_2 concentrations for the purpose of determining compliance with the revisions to the SO_2 NAAQS.

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

Executive Order 12898 (59 FR 7629; Feb. 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health effects on any population, including any minority or low-income population. The rule will establish uniform national standards for SO_2 in ambient air.

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September 22, 2011

VIA ELECTRONIC MAIL AND U.S. MAIL

Re: Supplemental Comments Concerning GenOn Energy, Inc.'s Shawville Generating Station Draft Title V/State Operating Permit (ID No. 17-00001)

Dear Muhammad Zaman,

The Sierra Club has previously submitted comments concerning Pennsylvania Department of Environmental Protection's ("PaDEP") draft Title V permit for GenOn Energy, Inc.'s Shawville Generating Station ("Shawville" or "the plant"), and in those comments, the Sierra Club specifically raised the issue of the draft permit's failure to ensure that Shawville does not cause or contribute to violations of the new 1-hour SO2 National Ambient Air Quality Standard ("NAAQS").[1] Although it has taken several months of FOIA requests and processing to obtain from PaDEP information to model the Shawville Plant's SO2 emissions, The Sierra Club has now completed that process. The Sierra Club's modeling analysis demonstrates that Shawville is indeed causing nonattainment of the NAAQS. Accordingly, the Sierra Club submits the following supplemental comments demonstrating that Shawville alone places its surrounding county in nonattainment of the one-hour SO2 NAAQS.

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[1] At the time the draft permit was issued, and at the time the Sierra Club submitted its initial comments, the merger between Mirant Corp. and RRI Energy, Inc. to form GenOn Energy, Inc. had not yet been completed.

BACKGROUND

Statutory and Regulatory Background

The Clean Air Act and Federal Regulation of SO_2

Under the Clean Air Act ("CAA"), EPA is required to promulgate National Ambient Air Quality Standards ("NAAQS") for SO_2 and other pollutants to protect the public health and welfare. 42 U.S.C. § 7409. As per Section 109 of the CAA, national primary ambient air quality standards are standards requisite to protect the public health, allowing an adequate margin of safety. 42 U.S.C. § 7409(b).

In 1971, EPA first set the SO_2 NAAQS, establishing the primary annual SO_2 NAAQS at 0.03 ppm (80 micrograms per cubic meter ($\mu g/m^3$), primary 24-hour SO_2 NAAQS at 365 $\mu g/m^3$ (140 parts per billion (ppb)), and secondary 3-hour SO_2 NAAQS at 1300 $\mu g/m^3$ (500 ppb). 36 Fed. Reg. 8,186 (April 30, 1971). On June 3, 2010, EPA issued a new SO_2 NAAQS standard, recognizing that the prior 24-hour and annual SO_2 standards did not adequately protect the public against adverse respiratory effects associated with short term (5 minutes to 24 hours) SO_2 exposure. At the same time, EPA revoked those prior NAAQS, though it kept the prior standards in place for one year.

The new 2010 SO_2 NAAQS standard is a 1-hour standard set at 196 micrograms per cubic meter (75 ppb). 40 C.F.R. § 50.17(a). The new standard was established in the form of the 99th percentile of the annual distribution of the daily maximum 1-hour average concentrations. *Id* § 50.17(b). Due to both the shorter averaging time and the numerical difference, the new 1-hour SO_2 NAAQS is far more stringent than the prior SO_2 NAAQS. The new NAAQS is projected to have enormous beneficial effects for public health: EPA has estimated that 2,300-5,900 premature deaths and 54,000 asthma attacks a year will be prevented by the new standard. Envtl. Prot. Agency, *Final Regulatory Impact Analysis (RIA) for the SO_2 National Ambient Air Quality Standards (NAAQS) tbl. 5.14* (2010), attached hereto as Ex. 1.

In the final rule, EPA recognized the "strong source-oriented nature of SO_2 ambient impacts," Final Rule, 75 Fed. Reg. at 35,370, and concluded that the appropriate methodology for purposes of determining compliance, attainment, and nonattainment with the new NAAQS is modeling. *See* Final Rule, 75 Fed. Reg. at 35,551 (describing dispersion modeling as "the most technically appropriate, efficient, and readily available method for assessing short-term ambient SO_2 concentrations in areas with large point sources."). Accordingly, in promulgating the new SO_2 NAAQS, EPA explained that, for the 1-hour standard, "it is more appropriate and efficient to principally use modeling to assess compliance for medium to larger sources . . . ." *Id.* at 35,570. As such, EPA has noted that "even if monitoring does not show a violation," that absence of data is not determinative of attainment status absent modeling, and that monitoring in general is "less appropriate, more expensive, and slower to establish." *Id.*

The Clean Air Act Title V Permitting Program

The CAA requires all major sources to obtain a Title V permit as a condition of their operation. *See* 42 U.S.C. § 7661A(a) ("[I]t shall be unlawful . . . to operate . . . a major source . . . except in compliance with a permit issued by a permitting authority under this subchapter."). Such permits, whether issued by a delegated state permitting authority or by EPA itself, must include "[e]missions limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of permit issuance." 40 C.F.R. § 70.6(a)(1); *see also* 42 U.S.C. § 7416 (noting that states "may not adopt or enforce any emission standard or limitation which is less stringent than the standard or limitation" under federal law). Title V permits must contain limits sufficient to meet all "applicable requirements at the time of permit issuance." 40 C.F.R. § 70.6(a)(1); *see also* 40 C.F.R. § 70.2(1) (defining "applicable requirements" to mean "[a]ny standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA")

Title V permits expire five years after issuance. 40 C.F.R. § 70.6(a)(2). Renewal applications must be submitted at least six months before expiration of a governing permit. *Id.* at § 70.5(a)(1)(iii). Once a completed renewal application has been submitted, the extant permit governs the source's operation until the application is acted upon. *Id.* at § 70.7(b). However, the federal regulations require speed in finalizing permits. *See* 40 C.F.R. § 70.7(a)(2) ("[T]he program shall provide that the permitting authority take final action on each permit application (including a request for permit modification or renewal) within 18 months . . . after receiving a complete application.")

Pennsylvania Regulations

Pursuant to the federally approved Pennsylvania SIP, NAAQS are automatically incorporated into the Pennsylvania SIP. *See* 25 Pa. Code § 131.2 (noting that the "National Ambient Air Quality Standards, promulgated by the Administrator of the EPA under the Clean Air Act are hereby incorporated" into the Pennsylvania SIP). As such, the 1-hour SO_2 NAAQS is part of the governing SIP for Pennsylvania. *Id.*; *see also id.* at § 131.1 (noting that the purpose of such limits in Pennsylvania is to "establish[] the maximum concentrations of air contaminants which will be permitted to exist in the ambient air, at the point of its use").

Under Pennsylvania law, it is "**unlawful to fail to comply with or to cause or assist in the violation of any of the provisions of this act or the rules and regulations adopted under this act** . . . or to cause a public nuisance; or to cause air pollution . . . . **The owner or operator of an air contamination source shall not allow pollution of the air,** water or other natural resources of the Commonwealth resulting from the source." 35 P.S. § 4008 (2011). (emphasis added).

Similarly, the federally-approved Pennsylvania State Implementation Plan ("SIP") provides that "**[n]o person shall** cause, suffer, or **permit air pollution**" in Pennsylvania. 25 Pa. Code §121.7 (emphasis added). Pennsylvania regulations—again, incorporated into the federally approved SIP—define "air pollution" as follows:

> Air pollution—The presence in the outdoor atmosphere of **any form of contaminant**, including, but not limited to, the discharging from stacks, chimneys, openings, buildings, structures, open fires, vehicles, processes or any other source of any smoke, soot, fly ash, dust, cinders, dirt, noxious or obnoxious acids, fumes, oxides, gases, vapors, odors, toxic, hazardous or radioactive substances, waste or other matter in a place, manner or **concentration inimical or which may be inimical to public health**, safety or welfare **or which is or may be injurious to human, plant or animal life** or to property or which unreasonably interferes with the comfortable enjoyment of life or property.

25 Pa. Code § 121.1 (emphasis added).

Pennsylvania has delegated authority under the CAA to grant Title V permits. As such, Pennsylvania Title V permits must include operation and emission limitations sufficient to ensure that the permitted facility is in compliance with all "applicable requirements **at the time of permit issuance**." 25 Pa. Code § 127.512 (emphasis added). Under Pennsylvania regulations, an "applicable requirement" is defined, in part, as a "standard provided for in the Commonwealth's SIP approved by the EPA." *Id.* at § 121.1.

Further, Pennsylvania regulations incorporated in the SIP require timely action in finalizing Title V permits: it is an "appealable action" when PaDEP fails to "issue or deny a new permit prior to the expiration date of the previous permit for which a timely renewal application has been filed shall be an appealable action." 25 Pa. Code § 127.446(d).

Factual Background

SO_2 Pollution Has Significant Adverse Health Effects

The Environmental Protection Agency has arrived at the conclusion that exposure to SO_2 in even very short time periods—such as five minutes—causes decrements in lung function, aggravation of asthma, and respiratory and cardiovascular morbidity. *See* Envtl. Prot. Agency, EPA/600/R-08/047F, *Integrated Science Assessment for Sulfur Oxides—Health Criteria* ch. 5 tbls. 5-1, 5-2 (2008), attached hereto as Ex. 2; Primary National Ambient Air Quality Standard for Sulfur Dioxide Final Rule, 75 Fed. Reg. 35,520, 35,525 (June 22, 2010) (hereinafter "Final Rule"), attached hereto as Ex. 3; *see also* Envtl. Prot. Agency, *Our Nation's Air: Status and Trends Through 2008* 4 (2010) (noting that the health effects of sulfur dioxide exposure include aggravation of asthma and chest tightness), attached hereto as Ex. 4. EPA has also determined that SO_2 exposure can also aggravate existing heart disease, leading to increased hospitalizations and premature deaths. *Sulfur Dioxide*, Envtl. Prot. Agency, http://www.epa.gov/oaqps001/sulfurdioxide/health.html, attached hereto as Ex. 5. Further, short-term SO_2 exposure is especially risky for children with asthma. *See* Final Rule, 75 Fed. Reg. at 35,525. According to EPA, fossil fuel combustion at electric utilities contributes the majority of anthropogenic SO_2 emissions. Envtl. Prot. Agency, *Our Nations Air: Status and Trends Through 2008* 6 fig. 2 (2010).

The Shawville Plant

The Shawville Plant is a 626 megawatt ("MW") coal-fired facility in Clearfield County, Pennsylvania, near the intersection of Routes 879 and 970. All four of its boiler units came online between 1954 and 1960; none of them are equipped with any form of sulfur controls. In 2009, the facility emitted nearly 39,000 tons of SO_2.

Clearfield County has roughly 82,000 residents, according to 2010 census data, and more than 6,000 of them live in Clearfield Borough, which is roughly 4 miles south of the Shawville Plant. As explained more fully below, an analysis of SO_2 emissions from the Shawville Plant conducted by the Sierra Club shows that the Shawville facility is, as currently permitted, predicted to cause nonattainment of the SO_2 NAAQS in much of Clearfield County, with particularly severe effects in areas—such as Clearfield Borough—close to the Plant.

The Shawville Title V Operating Permit

The currently-governing Title V permit for the Shawville facility expired in October of 2005. Five years later PaDEP released a draft renewal permit in late 2010.

On November 17, 2010, Sierra Club submitted a Right to Know request to PA DEP requesting documents relevant to the Shawville Plant's Title V permitting, as well as to its NPDES permitting. To facilitate more rapid processing of the document request, the request was narrowed and Sierra Club travelled to PaDEP to copy documents on December 23, 2010.

On January 4, 2011, the Sierra Club timely submitted comments on the draft Title V permit for the Shawville station. *See* Sierra Club Shawville Title V Comments (hereinafter "Shawville Comments"), attached hereto as Exhibit 6. In pertinent part, the Sierra Club objected to the failure of the draft permit to provide for compliance with the 1-hour SO_2 NAAQS. Specifically, the Sierra Club noted that states "may not adopt or enforce any emission standard or limitation which is less stringent than the standard or limitation" under federal law (*see* 42 U.S.C. § 7416), and called for PaDEP to revise the Shawville permit to "to include the new one-hour SO_2 NAAQS in the provisions that preclude the plant from causing or contributing to ambient air quality exceedences." *See* Shawville Comments at 9.[2]

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[2] The Sierra Club also noted that the draft permit lacked sufficient monitoring requirements for the plant's particulate matter emissions, lacked a compliance schedule to

As of this date, the Sierra Club has received no response from PaDEP concerning these comments; nor has PaDEP released a further revised permit.

On March 24, 2011, EPA released modeling guidance for evaluating compliance with the new 1-hour SO_2 NAAQS and designating areas in attainment or nonattainment of the 1-hour SO_2 NAAQS. *See Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standard* (hereinafter "March 2011 Guidance"), attached hereto as Ex. 7. This March 2011 Guidance specified general protocols for performing aerial dispersion modeling appropriate to determine whether a source or sources collectively were causing nonattainment of the 1-hour SO_2 NAAQS. *Id.* Similar to EPA's prior statements in the Final Rule, the March 2011 Guidance affirms the primacy of modeling in determining attainment/nonattainment of the new NAAQS. *See id.* at 4.

After EPA released the SO_2 modeling guidance, the Sierra Club subsequently submitted additional Right to Know requests to the PaDEP to obtain additional information necessary to model the Plant's impacts on SO_2 concentrations in the ambient air and determine whether or not the Plant would cause a violation of the new 1-hour SO_2 NAAQS. The Sierra Club received these data on May 27, 2011.

Sierra Club has now completed the modeling and is submitting the modeling results herewith.

SUBSTANTIVE COMMENTS

PaDEP Must Timely Ensure Shawville's Compliance with the 1-Hour SO_2 NAAQS

As the Sierra Club noted in its original comments on the draft Title V permit for the Shawville plant, the draft permit fails to include emissions limitations sufficient to ensure compliance with the new NAAQS. This is improper, and must be remedied in the final permit. Further, this permit must be finalized soon, as required by governing law.

The Draft Permit Would Allow Shawville to Cause Extreme Nonattainment Over a Vast Area

The Sierra Club engaged AMI Environmental to perform SO_2 aerial dispersion modeling of emissions from the Shawville plant. *See* AERMOD Modeling of the SO_2 Impacts of the GenOn Shawville Coal Plant Final Report (hereinafter "Shawville Modeling"),

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remedy significant, ongoing issues with opacity violations, failed to ensure that the plant would not cause or contribute to violations of the 1-hour NAAQS for NO_2, and failed to provide sufficient specificity in its requirements for continuous emissions monitoring for SO_2, CO_2, and NO_x, as required by 40 C.F.R. § 75.10.

attached hereto as Ex. 8.[3] The modeling performed is consistent with EPA's approach to determining attainment or nonattainment of the new NAAQS.

The Shawville Modeling was based on both the facility's permitted SO_2 emissions[4] (the "allowables"), and on the actual emissions of SO_2 reported by the Shawville for the peak plantwide emission hour in 2010 (the "actuals"). *See id.* at 4.

The modeling predicts that Shawville by itself is causing extremely severe violations of the NAAQS. Looking at the results from modeling the allowable emissions, Shawville is predicted to cause a 4th-highest daily maximum concentration of 2,055.3 µg/m^3. *Id.* at 6. Similarly, looking at the results from modeling the actual emissions, Shawville is predicted to cause a 4th-highest daily maximum concentration of 1,431.2 µg/m^3. *Id.* at 8. Both of these modeled results are roughly an order of magnitude greater than the NAAQS of 196.2 µg/m^3. In Clearfield Borough, the modeling analysis shows concentrations of between 350 and 500 µg/m^3—well-above the standard.

Predicted 1-Hour SO2 Impacts by Allowable Emissions of the GenOn Shawville Plant

Pollutant	Project Conc. (ug/m3)	Background Conc. (ug/m3)	Total Conc. (ug/m3)	NAAQS (ug/m3)	NAAQS Exceed	Percent Over NAAQS
1-hour SO2 (4th highest)	2,055.3	33	2,088.3	196	**YES**	**965%**

Predicted 1-Hour SO2 Impacts by 2010 Actual Emissions of the GenOn Shawville Plant

Pollutant	Project Conc. (ug/m3)	Background Conc. (ug/m3)	Total Conc. (ug/m3)	NAAQS (ug/m3)	NAAQS Exceed	Percent Over NAAQS
1-hour SO2 (4th highest)	1,431.2	33	1,464.2	196	**YES**	**647%**

The area of nonattainment is also quite large. The Shawville Modeling predicts nonattainment extending out roughly 30 miles on all sides of the facility. *See id.* at 7, 9.

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[3] Also included with these supplemental comments are the underlying modeling files themselves.

[4] These values were taken from the governing, expired Title V permit. *See* Shawville Modeling at 4. The permitted emissions of SO_2 in the draft permit are exactly the same.

The model additionally predicts that a reduction in allowable emissions of at least 92% would be required to ensure attainment. *Id.* at 10.

The Clean Air Act and Pennsylvania's SIP Require That Any Title V Permit for the Shawville Plant Ensure Compliance with the 1-Hour SO_2 NAAQS

As noted above, EPA has set the 1-hour SO_2 NAAQS at 196.2 $\mu g/m^3$, evaluated as the 99th percentile (or fourth-highest) annual daily maximum concentration, averaged over three years. 40 C.F.R. § 50.17(a)-(b). For two reasons, any Title V permit issued for the Shawville plant must incorporate emission limits sufficient to prevent exceedences of this threshold. First, the method by which the Pennsylvania SIP builds on the NAAQS constitutes a requirement inputable to Title V permitting. Second, Pennsylvania's prohibition on harmful air pollution incorporates the standards underpinning the health-based SO_2 NAAQS, and is therefore an additional independent requirement for Title V permitting.

Both federal regulations and Pennsylvania regulations incorporated into Pennsylvania's SIP require that any Title V permit issued contain limits sufficient to meet all "applicable requirements at the time of permit issuance." 40 C.F.R. § 70.6(a)(1); *accord* 25 Pa. Code § 127.512. The term "all applicable requirements" is defined by both the federal regulations and Pennsylvania's regulations to include standards or requirements in the SIP. *See* 40 C.F.R. § 70.2(1) (defining "applicable requirements" to mean "[a]ny standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA"); 25 Pa. Code § 121.1 (defining "applicable requirements" to mean "standard[s] provided for in the Commonwealth's SIP approved by the EPA").

Turning to the first mechanism by which the limits in the 1-hour SO_2 NAAQS are build upon by the Pennsylvania SIP to form applicable requirements for Title V permitting, Pennsylvania's SIP sets standards for pollutant levels, declaring them to be "maximum values that may not be exceeded." 25 Pa. Code § 131.3. The SIP further states that "[t]he National Ambient Air Quality Standards, promulgated by the Administrator of the EPA under the Clean Air Act are hereby incorporated, by reference, as part of" these standards. *Id.* at § 131.2. Importantly, the Pennsylvania SIP treats such standards in two ways: both as "standards against which existing air quality may be compared," and as "maximum concentrations of air contaminants which will be permitted to exist in the ambient air, at the point of its use." *Id.* at § 131.1.

Because the NAAQS are used by the SIP to create concentration limits "permitted to exist in the ambient air, at the point of its use" those limits constitute "standard[s] or other requirement[s] provided for in the applicable implementation plan" such that the limits in the NAAQS constitute "applicable requirements" that must be incorporated into Title V permits. Put another way, the Pennsylvania SIP does not merely incorporate the NAAQS, but also requires that the concentrations in the NAAQS are the limits of what is "*permitted*." *Id.* Accordingly, the final Title V permit for Shawville must incorporate emissions limitations sufficient to avoid exceedence of the NAAQS.

Additionally, the SIP includes a second requirement that the 1-hour SO_2 NAAQS limits be incorporated in Title V permits. The Pennsylvania SIP expressly forbids any person from "caus[ing], suffer[ing], or permit[ting] air pollution" in Pennsylvania. 25 Pa. Code § 121.7. Air pollution is defined as pollutants in the air in any "concentration inimical or which may be inimical to public health, safety or welfare or which is or may be injurious to human, plant or animal life". *Id.* at § 121.1. The specific limit in the 1-hour SO_2 NAAQS of 196 micrograms per cubic meter is as such dispositive *authority* that such levels of SO_2 pollution are "inimical to public health" or "injurious" to human life: the NAAQS and EPA's conclusions regarding the impact of SO_2 pollution demonstrate what constitutes air pollution. As such, the limits in the NAAQS provide the numerical translation of the SIP's prohibition on air pollution, and are therefore incorporated into Title V permit limits.

Accordingly, for multiple reasons PaDEP must revise the Shawville draft permit to include emissions limitations sufficient to prevent NAAQS exceedences. AERMOD modeling performed pursuant to EPA requirements demonstrates that Shawville is, as currently permitted—with limits identical to the proposed SO_2 emission limits in the draft permit—causing extreme violations of the NAAQS. *See* Shawville Modeling. These violations include predicted allowable emissions over ten times the NAAQS limit. *See id.* at 6. Thus, to ensure compliance with the NAAQS, any Shawville Title V permit must reduce allowable emissions by at the very least 92%. *Id.* at 10.

Pennsylvania State Law Additionally Requires Compliance with the1-Hour SO_2 NAAQS

Even if the CAA did not require compliance with the 1-hour SO_2 NAAQs, Pennsylvania state law would. As noted above, under Pennsylvania law, it is "**unlawful to fail to comply with or to cause or assist in the violation of any of the provisions of this act or the rules and regulations adopted under this act** . . . or to cause a public nuisance; or to cause air pollution . . . . **The owner or operator of an air contamination source shall not allow pollution of the air,** water or other natural resources of the Commonwealth resulting from the source." 35 P.S. § 4008 (2011). (emphasis added). Pennsylvania regulations moreover adopt the NAAQS as the air quality standards for Pennsylvania. *See* 25 Pa. Code § 131.2. As such, PaDEP's failure to ensure compliance with the 1-hour SO_2 NAAQS is independently actionable under state law. PaDEP must therefore dramatically reduce the sulfur pollution Shawville is permitted to emit.

Action on Shawville's Title V Permit Renewal Is Long Overdue

A permit containing such reductions must be finalized very soon. Pennsylvania law requires that renewal Title V permits be finalized *before* expiration of the prior permit. 25 Pa. Code § 127.446(d). Similarly, federal regulations require that any Title V permitting program delegated to state agencies provides for speedy issuance of renewal permits. *See* 40 C.F.R. § 70.7(a)(2) ("[T]he program shall provide that the permitting authority take final action on each permit application (including a request for permit modification or renewal) within 18 months . . . after receiving a complete application.").

Here, since Shawville submitted a renewal application in 2004, and the facility's Title V permit expired nearly *six years ago*, corrective action is long overdue. *See* 25 Pa. Code § 127.446(d) (parties may appeal PaDEP's failure to issue a renewal permit); *MFS, Inc. v. DiLazaro*, 771 F.Supp.2d 382, 395 (E.D.Pa. 2011) (same).

CONCLUSION

As explained above, the final permit for the Shawville plant must include emissions limitations sufficient to ensure compliance with the 1-hour SO_2 NAAQS. Because modeling performed pursuant to EPA guidelines demonstrates that emissions reductions of at least 92% would be required to avoid Shawville single-handedly causing nonattainment, the limits contemplated in the draft permit are vastly too permissive. A final permit, incorporating appropriately greatly diminished SO_2 pollution allowances, should be released as soon as possible.

Sincerely,

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AERMOD Modeling of SO2 Impacts of the GenOn Shawville Coal Plant

Final Report

September 14, 2011

Prepared for

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Table of Contents

I. INTRODUCTION

This document presents the methodologies and results of an application of the AERMOD model to predict the air quality impacts of sulfur dioxide (SO2) emitted by the Shawville Generating Station. Shawville is a coal-fired power plant operated by GenOn Energy near Shawville, Clearfield County, Pennsylvania (Figure 1). It consists of four coal-fired boilers with a total electric generating capacity of 626 MW (gross). SO2 impacts predicted by the AERMOD model were compared against the 1-hour SO2 National Ambient Air Quality Standard (NAAQS) of 75 ppb (or 196 ug/m3) which was promulgated in June 2010 by the U.S. Environmental Protection Agency (EPA).

Figure 1. GenOn Shawville Coal Plant

II. MODELING METHODOLOGIES

This section documents the methodologies and assumptions used in the generation of modeling inputs such as source emissions, stack parameters, receptors and meteorological data.

A. Model Version

Version 11103 of the AERMOD model has been used in the modeling study. It is currently the latest version of the model that has been approved by the US Environmental Protection Agency (USEPA, 2011). It predicts the 1-hour SO2 concentrations that can be compared against the 1-hour NAAQS which is attained when the 3-year average of the 99th percentile of the daily maximum 1-hour concentrations does not exceed 75 ppb (or 196 ug/m3) at each monitor within an area (USEPA, 2010a; 2010b).

B. Source Emissions

Four coal-fired boilers at the plant emit SO2. Based on the facility's governing Title V permit, maximum hourly allowable emissions by boiler are as follows:

- 5,380 lbs/hr each for Unit 1 and Unit 2. Each of these boilers has a rating of 1,345 MMBtu/hr and an emission limit of 4 lbs/MMBtu at any time.
- 7,160 lbs/hr each for Unit 3 and Unit 4. Each of these boilers has a rating of 1,790 MMBtu/hr and an emission limit of 4 lbs/MMBtu at any time.

In addition to the above allowable emissions, the maximum actual emissions in 2010 have also been modeled with hourly rates that occurred on May 26, 2010, hour 09. The following actual emissions have been retrieved from the US EPA Clean Air Market database:

- 3,744.7 lbs/hr for Unit 1.
- 5,076.1 lbs/hr for Unit 2,
- 5,055.982 lbs/hr for Unit 3 and,
- 4,910.818 lbs/hr for Unit 4.

The above actual emissions represent a 25% reduction of the maximum allowable emissions. Both allowable and actual emissions were modeled as emitted from the plant's two stacks (Stack1 for Units 1 and 2; Stack 2 for Units 3 and 4). They have been converted to grams per second (g/s) in Table 1 as required by the AERMOD model.

C. Stack Parameters

Stack parameters (stack height, diameter, temperature and exit velocity) for the two stacks are shown in Table 1. They have been taken from the 2009 Source Data Report and have been used in modeling both the maximum allowable and 2010 actual emissions.

Stack 2 has a physical stack height of 260.30 m but it has been modeled with a GEP stack height of 100.20 m in a previous modeling study performed by ENSR/AECOM for Reliant Energy (AECOM, 2008). Reliant Energy was the previous operator of the Shawville plant. Building dimensions for both stacks have also been taken from this Reliant modeling study.

Table 1. Plant SO2 Allowable and 2010 Actual Emissions & Stack Parameters

Stack	Allowable SO2 (g/s)	Actual SO2 (g/s)	Height (m)	Diameter (m)	Temperature (K)	Velocity (m/s)
Stack 1	1,355.76	1,111.421	182.88	3.81	414.26	54.71
Stack 2	1,804.32	1,255.817	100.20	5.79	390.37	28.09

D. Receptors

Receptors in the previous Reliant modeling study used the outdated NAD27 datum and do not cover a geographical area large enough to capture the 1-hour impacts. The current AERMOD modeling uses a Cartesian grid of discrete receptors that are located within a radius of 50 km around the Shawville plant. The receptor grid has varying resolutions: 100 m within the first 10 km and 500 m between 10 km and 50 km. Receptors located on-site within the plant boundaries have been removed from consideration. A total of 84,192 receptors (55,068 receptors within 30 km and 29,124 receptors between 30 km and 50 km) have been used in the AERMOD modeling. A flagpole height of 1.5 m was also assigned to the modeled receptors. The preprocessor AERMAP has been employed to obtain terrain elevations at these receptors using the NED data and the NAD83 datum.

E. Meteorological Data

The AERMOD modeling uses an onsite meteorological dataset collected at a site located 0.8 km northwest of the plant (AECOM, 2008). This site had a 100-m instrumented tower and Sound Detection and Ranging (SODAR) equipment, and data were collected from November 22, 1993 to November 21, 1994. The collected data have been processed and used in the previous Reliant modeling study. The 1994 onsite dataset includes upper-air data from Pittsburgh. This dataset has no calm hours and only 120 hours with missing data.

F. Background Concentration

For comparison with the SO2 1-hour NAAQS, background concentrations at a monitoring station are added to the concentrations predicted by the AERMOD model. There is no SO2 monitoring station in Clearfield County. A concentration of 33 ug/m3 that corresponds to the maximum measurement at a background monitor near the Shawville plant has been used in the previous Reliant modeling study. The current

AERMOD modeling also uses this background concentration of 33 ug/m3. It is lower than the design values based on the 2008-2010 monitoring data in neighboring counties: 76 ug/m3 in Centre County, 123 ug/m3 in Blair County, 173 ug/m3 in Cambria County and 235 ug/m3 in Indiana County. Pennsylvania Department of Environmental Protection (PADEP) has recently recommended the designation of Indiana County as non-attainment of the 1-hour SO2 NAAQS (PADEP, 2011).

III. MODELING RESULTS

In June 2010, US EPA announced a new 1-hour NAAQS which is attained when the 3-year average of the 99th percentile of the daily maximum 1-hour SO2 concentrations does not exceed 75 ppb (or 196 ug/m3) at each monitor within an area. Subsequently, US EPA issued in August 2010 a modeling guidance for using the AERMOD model with one year or five years of meteorological data (USEPA, 2010b). According to the US EPA, the 4th highest maximum daily 1-hour concentration obtained with one year of onsite data should be used in the NAAQS comparison.

A. Predicted Impacts by Allowable Emissions

An AERMOD modeling run with the 1994 onsite data and maximum allowable emissions was performed. SO2 modeling results for the 4th highest concentrations are summarized in Appendix A and presented in Table 2. The AERMOD model has predicted a 4th highest (99th percentile) concentration of 2,055.3 ug/m3 from the plant emissions alone. This concentrations largely exceeds, by more than a factor of 10, the NAAQS of 196 ug/m3. With the background of 33 ug/m3, the maximum total 4th highest concentration is 2,088.3 ug/m3 which is 965% above the 1-hour NAAQS of 196 ug/m3. The maximum 99th percentile has been predicted to occur at about 4.9 km southeast of the plant. A plot of the contour of 196 ug/m3 is shown in Figure 2. The area with concentrations exceeding 196 ug/m3, i.e. violating the 1-hr NAAQS due to the plant emissions alone, has a radius of about 30 miles around the plant. Figure 3 shows the area near Clearfield with 1-hour NAAQS exceedances.

The emission reduction required to mitigate the NAAQS exceedances can be calculated from the formula $R = [C-(196-B)]/C$ where C is the plant 4th highest concentration and B is the background. With C=2,055.3 ug/m3 and B=33 ug/m3, the emission reduction is R= 0.92 or 92%. This 92% reduction will decrease the allowable emissions from 25,080 lbs/hr to 2006 lbs/hr.

Table 2. Predicted 1-Hour SO2 Impacts by Allowable Emissions of the GenOn Shawville Plant

Pollutant	Project Conc. (ug/m3)		Total Conc. (ug/m3)	NAAQS (ug/m3)	NAAQS Exceed	Percent Over NAAQS
1-hour SO2 (4th highest)	2,055.3	33	2,088.3	196	**YES**	**965%**

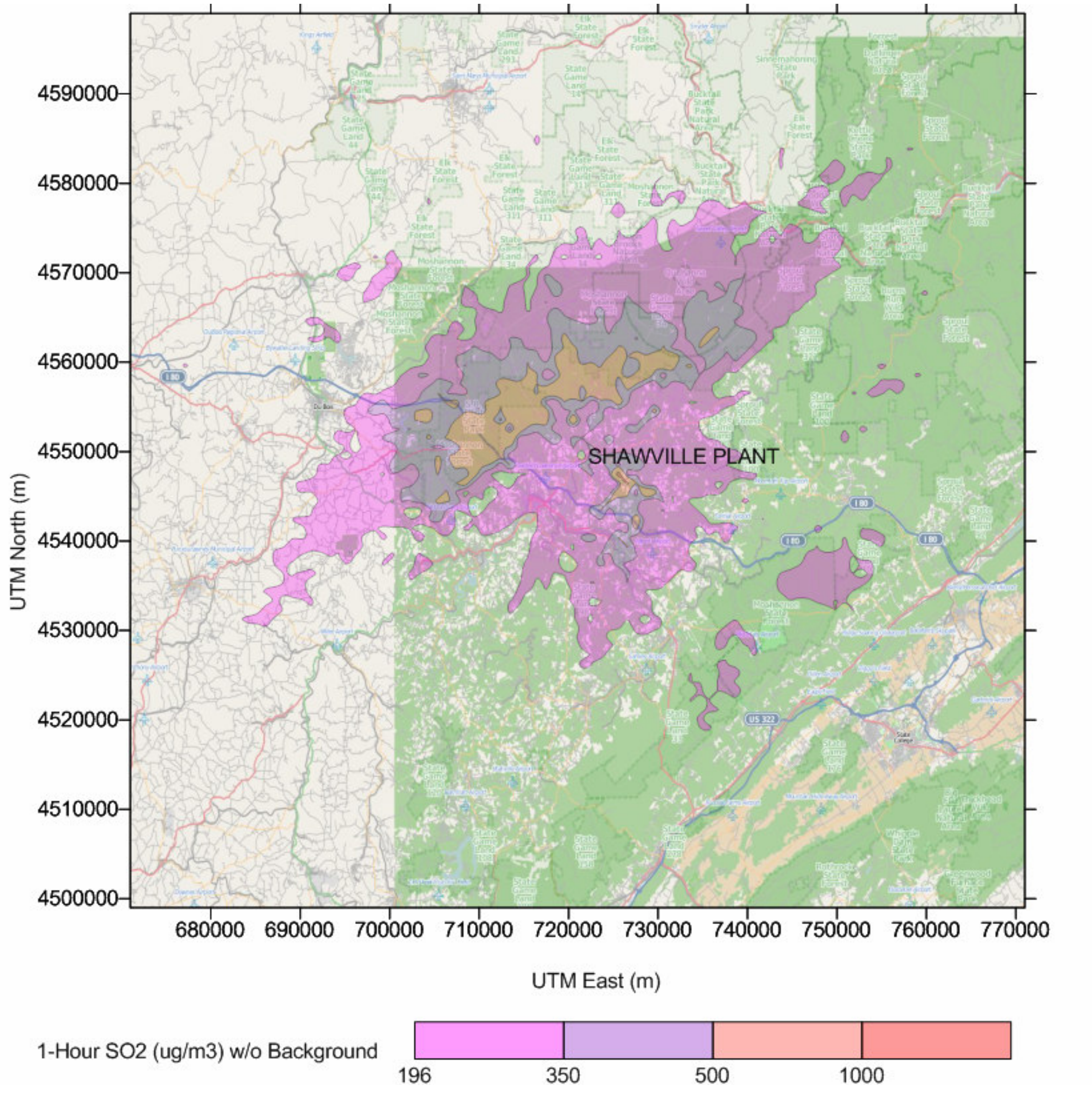

Figure 2. Total Area with 4th Highest SO2 Concentrations Exceeding the 1-Hour NAAQS of 196 ug/m3 by Plant Allowable Emissions Alone

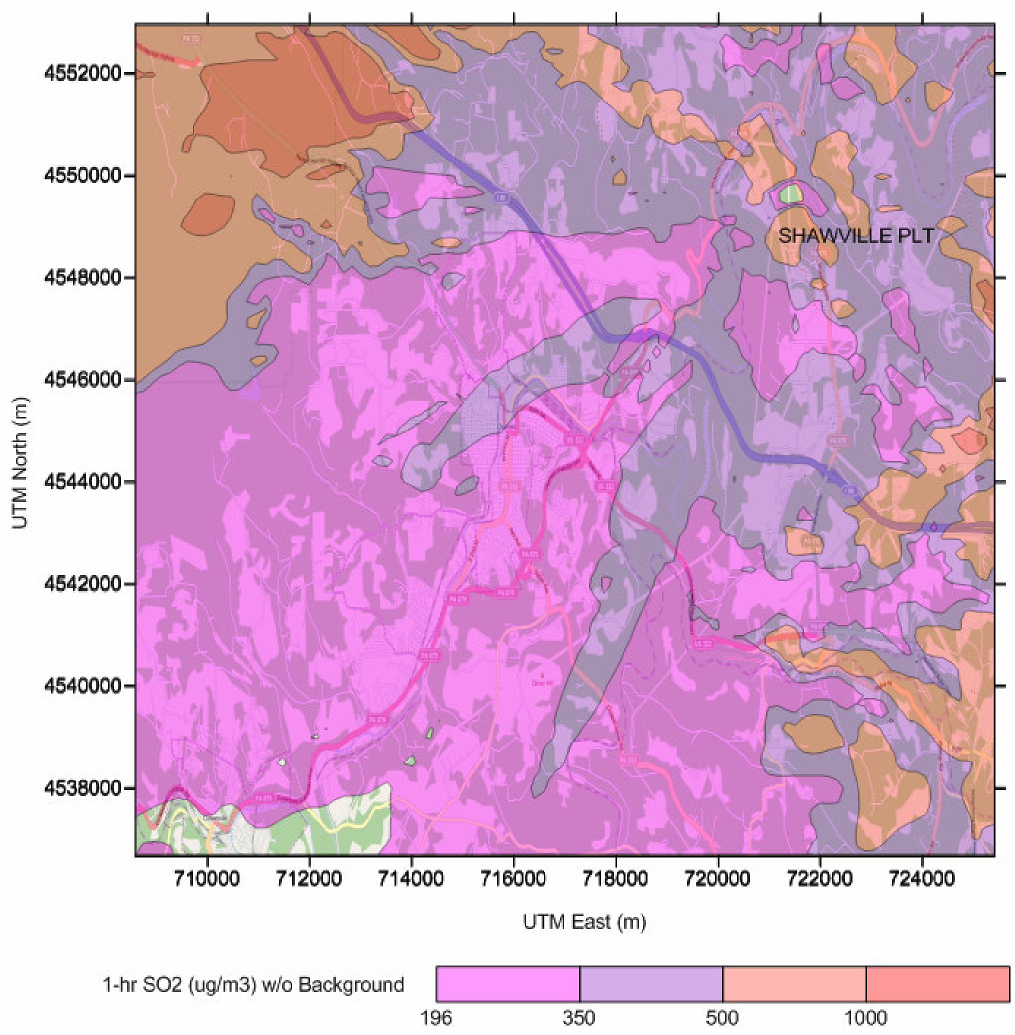

Figure 3. Area near Clearfield with 4th Highest SO2 Concentrations Exceeding the 1-Hour NAAQS of 196 ug/m3 by Plant Allowable Emissions Alone

B. Predicted Impacts by 2010 Actual Emissions

An AERMOD modeling run with the 1994 onsite data and maximum actual hourly emissions in 2010 was also performed. SO2 modeling results for the 4th highest concentrations are summarized in Appendix B and presented in Table 3. The AERMOD model predicted a 4th highest (99th percentile) concentration of 1,431.2 ug/m3 from the plant emissions alone. This concentration largely exceeds, by more than a factor of 6, the NAAQS of 196 ug/m3. This 99th percentile concentration -- based on the maximum hourly plant-wide emissions from 2010 -- is lower by about 30% than the 99th percentile predicted for the maximum allowable emissions. With the background of 33 ug/m3, the maximum total 4th highest concentration is 1,464.2 ug/m3 which is 647% above the 1-hour NAAQS of 196 ug/m3. The maximum 99th percentile has been predicted to occur at the same receptor of the maximum 99th percentile predicted for the allowable emissions, about 4.9 km southeast of the plant. A plot of the contour of 196 ug/m3 is shown in Figure 4. The area with concentrations exceeding 196 ug/m3, i.e. violating the 1-hr NAAQS due to the plant emissions alone, has a radius of about 30 miles northeast and southwest of the plant. Figure 5 shows the area near Clearfield with 1-hr NAAQS exceedances.

Table 3. Predicted 1-Hour SO2 Impacts by 2010 Actual Emissions of the GenOn Shawville Plant

Pollutant	Project Conc. (ug/m3)		Total Conc. (ug/m3)	NAAQS (ug/m3)	NAAQS Exceed	Percent Over NAAQS
1-hour SO2 (4th highest)	1,431.2	33	1,464.2	196	**YES**	**647%**

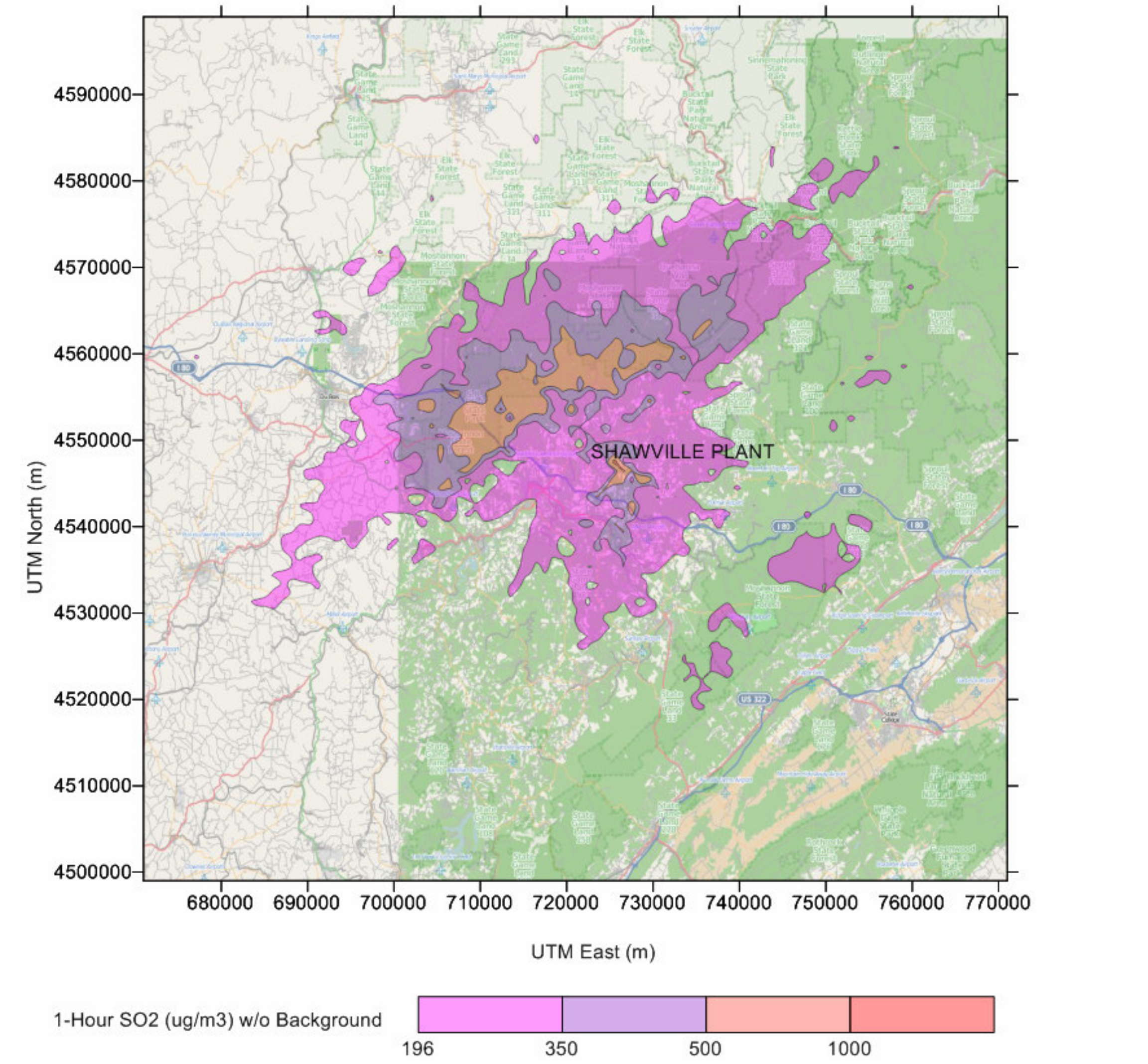

Figure 4. Total Area with 4th Highest SO2 Concentrations Exceeding the 1-Hour NAAQS of 196 ug/m3 by Plant 2010 Actual Emissions Alone

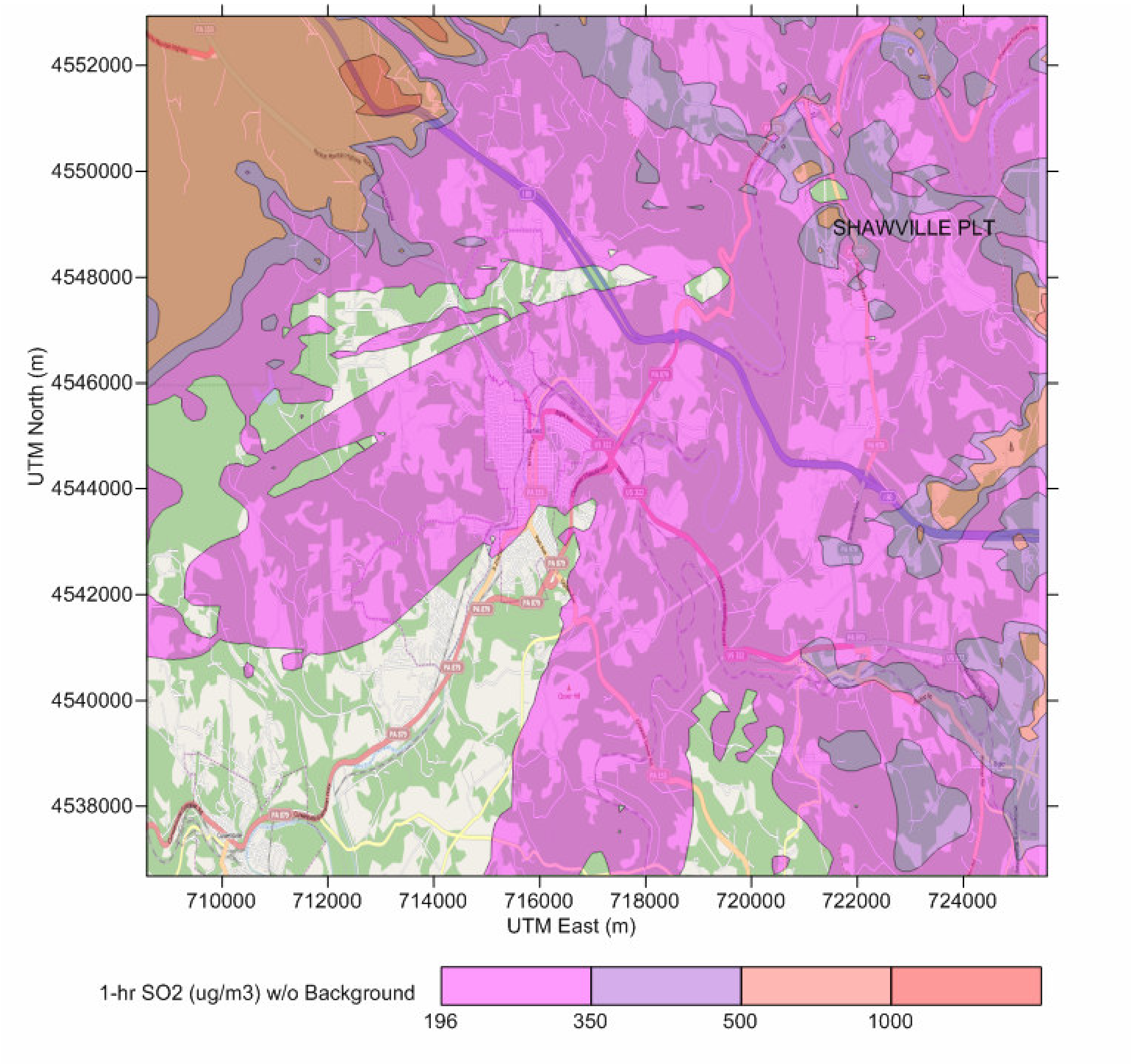

Figure 5. Area near Clearfield with 4th Highest SO2 Concentrations Exceeding the 1-Hour NAAQS of 196 ug/m3 by Plant 2010 Actual Emissions Alone

IV. CONCLUSIONS

Air quality impacts of SO2 emissions from the GenOn Shawville facility have been analyzed with the AERMOD model. Using maximum allowable emissions and 2010 actual emissions, the 1994 onsite meteorological data and the latest US EPA modeling guidance, the AERMOD model has predicted large exceedances (more than a factor of 9 by the allowable emissions and more than a factor of 6 by the 2010 actual emissions) of the SO2 1-hour NAAQS of 196 ug/m3. The plant alone has also been shown to cause a large area with a radius of about 30 miles where the concentrations exceed this NAAQS. Thus, SO2 impacts from the Shawville coal plant are extremely significant since its SO2 emissions alone cause large exceedances of the 1-hour NAAQS and a large area of NAAQS violations. A 92% reduction in allowable SO2 emissions is required to mitigate these gross NAAQS violations.

IV. REFERENCES

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PADEP, 2011. Designation Recommendations for the 2010 1-hour SO2 NAAQS, June 2001.

U.S. EPA, 2011. Addendum to User's Guide of the AMS/EPA Regulatory Model AERMOD version 11103, March 2011. Available at: http://www.epa.gov/ttn/scram/models/aermod/aermod_userguide.zip

U.S. EPA, 2010a. *Guidance Concerning the Implementation of the 1-hour SO2 NAAQS for the Prevention of Significant Deterioration Program*. Memorandum issued on August 23, 2010 from Stephen D. Page, Director of OAQPS. Available at http://www.epa.gov/region07/air/nsr/nsrmemos/appwso2.pdf

U.S. EPA, 2010b. *Applicability of Appendix W Modeling Guidance for the 1-hour SO2 NAAQS*. Memorandum issued on August 23, 2010 from Tyler Fox, Leader of Air Quality Modeling Group, OAQPS. Available at http://www.epa.gov/region07/air/nsr/nsrmemos/appwso2.pdf

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Appendix A

Summary of AERMOD Modeling Results of Allowable Emissions

```
*** AERMOD - VERSION  11103 ***   *** Shawville Plant - SO2 run with 1994 Met  (AMI)                ***        08/06/11
                                  ***                                                         ***        13:55:57
                                                                                                          PAGE   5
              **MODELOPTs:  RegDFAULT CONC                                          ELEV      FLGPOL


                 *** THE SUMMARY OF MAXIMUM   1ST-HIGHEST MAX DAILY  1-HR RESULTS AVERAGED OVER   1
                                                        YEARS ***


                                         ** CONC OF SO2      IN MICROGRAMS/M**3                         **

                                                                                                    NETWORK
GROUP ID                 AVERAGE CONC              RECEPTOR  (XR, YR, ZELEV, ZHILL, ZFLAG)  OF TYPE  GRID-ID
                    - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -

   U12      1ST HIGHEST VALUE IS     1154.88138 AT (  711900.00,  4553400.00,   638.31,   638.31,    1.50)  DC
            2ND HIGHEST VALUE IS     1140.60487 AT (  711800.00,  4553400.00,   642.44,   665.88,    1.50)  DC
            3RD HIGHEST VALUE IS     1136.96679 AT (  711700.00,  4553500.00,   641.26,   672.41,    1.50)  DC
            4TH HIGHEST VALUE IS     1123.04665 AT (  711900.00,  4553300.00,   638.07,   666.87,    1.50)  DC
            5TH HIGHEST VALUE IS     1108.97785 AT (  711600.00,  4553600.00,   636.77,   676.26,    1.50)  DC
            6TH HIGHEST VALUE IS     1102.15536 AT (  711700.00,  4553400.00,   647.81,   671.51,    1.50)  DC
            7TH HIGHEST VALUE IS     1096.04946 AT (  711800.00,  4553500.00,   630.00,   675.27,    1.50)  DC
            8TH HIGHEST VALUE IS     1089.47044 AT (  711600.00,  4553500.00,   651.47,   672.05,    1.50)  DC
            9TH HIGHEST VALUE IS     1087.09581 AT (  711400.00,  4553700.00,   644.98,   674.23,    1.50)  DC
           10TH HIGHEST VALUE IS     1082.98835 AT (  711800.00,  4553300.00,   646.42,   668.40,    1.50)  DC

   U34      1ST HIGHEST VALUE IS     3229.46595 AT (  725600.00,  4547600.00,   529.76,   538.47,    1.50)  DC
            2ND HIGHEST VALUE IS     3229.26320 AT (  725200.00,  4547800.00,   515.95,   515.95,    1.50)  DC
            3RD HIGHEST VALUE IS     3217.22178 AT (  725600.00,  4547500.00,   532.57,   538.98,    1.50)  DC
            4TH HIGHEST VALUE IS     3200.43292 AT (  725500.00,  4547500.00,   529.38,   531.58,    1.50)  DC
            5TH HIGHEST VALUE IS     3200.43292 AT (  725500.00,  4547500.00,   529.38,   531.58,    1.50)  DC
            6TH HIGHEST VALUE IS     3200.38750 AT (  725700.00,  4547500.00,   536.35,   544.59,    1.50)  DC
            7TH HIGHEST VALUE IS     3186.85250 AT (  725500.00,  4547600.00,   523.69,   526.17,    1.50)  DC
            8TH HIGHEST VALUE IS     3168.68310 AT (  725700.00,  4547600.00,   533.10,   533.10,    1.50)  DC
            9TH HIGHEST VALUE IS     3158.36929 AT (  725400.00,  4547700.00,   518.95,   520.63,    1.50)  DC
           10TH HIGHEST VALUE IS     3138.22328 AT (  725800.00,  4547500.00,   541.26,   541.26,    1.50)  DC

   ALL      1ST HIGHEST VALUE IS     3235.87269 AT (  725600.00,  4547600.00,   529.76,   538.47,    1.50)  DC
            2ND HIGHEST VALUE IS     3234.18237 AT (  725200.00,  4547800.00,   515.95,   515.95,    1.50)  DC
            3RD HIGHEST VALUE IS     3222.87293 AT (  725600.00,  4547500.00,   532.57,   538.98,    1.50)  DC
            4TH HIGHEST VALUE IS     3207.05313 AT (  725700.00,  4547500.00,   536.35,   544.59,    1.50)  DC
            5TH HIGHEST VALUE IS     3205.26825 AT (  725500.00,  4547500.00,   529.38,   531.58,    1.50)  DC
            6TH HIGHEST VALUE IS     3205.26825 AT (  725500.00,  4547500.00,   529.38,   531.58,    1.50)  DC
            7TH HIGHEST VALUE IS     3191.94249 AT (  725500.00,  4547600.00,   523.69,   526.17,    1.50)  DC
            8TH HIGHEST VALUE IS     3176.15018 AT (  725700.00,  4547600.00,   533.10,   533.10,    1.50)  DC
            9TH HIGHEST VALUE IS     3163.45482 AT (  725400.00,  4547700.00,   518.95,   520.63,    1.50)  DC
           10TH HIGHEST VALUE IS     3146.25237 AT (  725800.00,  4547500.00,   541.26,   541.26,    1.50)  DC
```

```
 *** AERMOD - VERSION  11103 ***   *** Shawville Plant - SO2 run with 1994 Met  (AMI)                  ***
08/06/11
                                          ***                                   ***       13:55:57
                                                                                       PAGE   6
             **MODELOPTs:  RegDFAULT CONC                                  ELEV     FLGPOL


                *** THE SUMMARY OF MAXIMUM   4TH-HIGHEST MAX DAILY  1-HR RESULTS AVERAGED
                                          OVER   1 YEARS ***


                                   ** CONC OF SO2      IN MICROGRAMS/M**3                       **

                                                                                        NETWORK
GROUP ID                     AVERAGE CONC              RECEPTOR  (XR, YR, ZELEV, ZHILL, ZFLAG)  OF TYPE
                                                   GRID-ID
              - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -


  U12      1ST HIGHEST VALUE IS     575.29135 AT (  715000.00,  4556600.00,   690.91,   690.91,    1.50)  DC
           2ND HIGHEST VALUE IS     570.35110 AT (  715100.00,  4556500.00,   686.30,   686.30,    1.50)  DC
           3RD HIGHEST VALUE IS     568.30400 AT (  715000.00,  4556500.00,   690.29,   690.29,    1.50)  DC
           4TH HIGHEST VALUE IS     568.30400 AT (  715000.00,  4556500.00,   690.29,   690.29,    1.50)  DC
           5TH HIGHEST VALUE IS     565.66614 AT (  715100.00,  4556600.00,   688.64,   688.64,    1.50)  DC
           6TH HIGHEST VALUE IS     563.19101 AT (  715100.00,  4556400.00,   682.00,   682.00,    1.50)  DC
           7TH HIGHEST VALUE IS     560.28476 AT (  714900.00,  4556600.00,   691.85,   691.85,    1.50)  DC
           8TH HIGHEST VALUE IS     560.03619 AT (  714700.00,  4555800.00,   676.20,   678.94,    1.50)  DC
           9TH HIGHEST VALUE IS     556.91058 AT (  713000.00,  4554700.00,   656.80,   656.80,    1.50)  DC
          10TH HIGHEST VALUE IS     556.11267 AT (  714700.00,  4555900.00,   681.55,   681.55,    1.50)  DC

  U34      1ST HIGHEST VALUE IS    2043.66700 AT (  725600.00,  4547100.00,   519.27,   519.27,    1.50)  DC
           2ND HIGHEST VALUE IS    2036.01244 AT (  725800.00,  4547500.00,   541.26,   541.26,    1.50)  DC
           3RD HIGHEST VALUE IS    2023.61433 AT (  725500.00,  4547100.00,   520.21,   520.21,    1.50)  DC
           4TH HIGHEST VALUE IS    1965.59553 AT (  725900.00,  4547500.00,   541.50,   545.65,    1.50)  DC
           5TH HIGHEST VALUE IS    1935.44733 AT (  725700.00,  4547000.00,   518.77,   518.77,    1.50)  DC
           6TH HIGHEST VALUE IS    1931.82524 AT (  726000.00,  4547400.00,   541.21,   541.21,    1.50)  DC
           7TH HIGHEST VALUE IS    1931.43536 AT (  725700.00,  4547600.00,   533.10,   533.10,    1.50)  DC
           8TH HIGHEST VALUE IS    1901.96549 AT (  725500.00,  4547200.00,   515.63,   518.97,    1.50)  DC
           9TH HIGHEST VALUE IS    1900.79099 AT (  725800.00,  4547000.00,   518.93,   518.93,    1.50)  DC
          10TH HIGHEST VALUE IS    1888.01913 AT (  726100.00,  4546800.00,   524.85,   524.85,    1.50)  DC

  ALL      1ST HIGHEST VALUE IS    2055.32693 AT (  725600.00,  4547100.00,   519.27,   519.27,    1.50)  DC
           2ND HIGHEST VALUE IS    2044.17395 AT (  725800.00,  4547500.00,   541.26,   541.26,    1.50)  DC
           3RD HIGHEST VALUE IS    2035.96786 AT (  725900.00,  4547500.00,   541.50,   545.65,    1.50)  DC
           4TH HIGHEST VALUE IS    2025.14879 AT (  725500.00,  4547100.00,   520.21,   520.21,    1.50)  DC
           5TH HIGHEST VALUE IS    1952.79282 AT (  725700.00,  4547600.00,   533.10,   533.10,    1.50)  DC
           6TH HIGHEST VALUE IS    1939.87075 AT (  726000.00,  4547400.00,   541.21,   541.21,    1.50)  DC
           7TH HIGHEST VALUE IS    1937.26923 AT (  725700.00,  4547000.00,   518.77,   518.77,    1.50)  DC
           8TH HIGHEST VALUE IS    1935.70982 AT (  726100.00,  4547400.00,   539.30,   539.30,    1.50)  DC
           9TH HIGHEST VALUE IS    1907.60970 AT (  726000.00,  4547500.00,   543.69,   547.52,    1.50)  DC
          10TH HIGHEST VALUE IS    1907.60970 AT (  726000.00,  4547500.00,   543.69,   547.52,    1.50)  DC


                                   *** RECEPTOR TYPES:  GC = GRIDCART
                                                        GP = GRIDPOLR
                                                        DC = DISCCART
                                                        DP = DISCPOLR
```

Appendix B

Summary of AERMOD Modeling Results of 2010 Actual Emissions

```
*** AERMOD - VERSION  11103 ***   *** Shawville Plant - SO2 run 2 with 2010 acutal emissions  (AMI)        ***        08/19/11
                                   ***                                                      ***        14:00:03
                                                                                                     PAGE   5
                   **MODELOPTs:  RegDFAULT CONC                                 ELEV      FLGPOL


               *** THE SUMMARY OF MAXIMUM   1ST-HIGHEST MAX DAILY  1-HR RESULTS AVERAGED OVER   1
                                               YEARS ***


                                  ** CONC OF SO2      IN MICROGRAMS/M**3                         **

                                                                                        NETWORK
GROUP ID                  AVERAGE CONC              RECEPTOR  (XR, YR, ZELEV, ZHILL, ZFLAG)  OF TYPE  GRID-ID
                   - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -

U12       1ST HIGHEST VALUE IS     946.74531 AT (  711900.00,  4553400.00,   638.31,   638.31,    1.50)  DC
          2ND HIGHEST VALUE IS     935.04175 AT (  711800.00,  4553400.00,   642.44,   665.88,    1.50)  DC
          3RD HIGHEST VALUE IS     932.05934 AT (  711700.00,  4553500.00,   641.26,   672.41,    1.50)  DC
          4TH HIGHEST VALUE IS     920.64793 AT (  711900.00,  4553300.00,   638.07,   666.87,    1.50)  DC
          5TH HIGHEST VALUE IS     909.11465 AT (  711600.00,  4553600.00,   636.77,   676.26,    1.50)  DC
          6TH HIGHEST VALUE IS     903.52172 AT (  711700.00,  4553400.00,   647.81,   671.51,    1.50)  DC
          7TH HIGHEST VALUE IS     898.51625 AT (  711800.00,  4553500.00,   630.00,   675.27,    1.50)  DC
          8TH HIGHEST VALUE IS     893.12291 AT (  711600.00,  4553500.00,   651.47,   672.05,    1.50)  DC
          9TH HIGHEST VALUE IS     891.17625 AT (  711400.00,  4553700.00,   644.98,   674.23,    1.50)  DC
         10TH HIGHEST VALUE IS     887.80905 AT (  711800.00,  4553300.00,   646.42,   668.40,    1.50)  DC

U34       1ST HIGHEST VALUE IS    2247.72670 AT (  725600.00,  4547600.00,   529.76,   538.47,    1.50)  DC
          2ND HIGHEST VALUE IS    2247.58559 AT (  725200.00,  4547800.00,   515.95,   515.95,    1.50)  DC
          3RD HIGHEST VALUE IS    2239.20469 AT (  725600.00,  4547500.00,   532.57,   538.98,    1.50)  DC
          4TH HIGHEST VALUE IS    2227.51955 AT (  725500.00,  4547500.00,   529.38,   531.58,    1.50)  DC
          5TH HIGHEST VALUE IS    2227.51955 AT (  725500.00,  4547500.00,   529.38,   531.58,    1.50)  DC
          6TH HIGHEST VALUE IS    2227.48793 AT (  725700.00,  4547500.00,   536.35,   544.59,    1.50)  DC
          7TH HIGHEST VALUE IS    2218.06750 AT (  725500.00,  4547600.00,   523.69,   526.17,    1.50)  DC
          8TH HIGHEST VALUE IS    2205.42149 AT (  725700.00,  4547600.00,   533.10,   533.10,    1.50)  DC
          9TH HIGHEST VALUE IS    2198.24302 AT (  725400.00,  4547700.00,   518.95,   520.63,    1.50)  DC
         10TH HIGHEST VALUE IS    2184.22129 AT (  725800.00,  4547500.00,   541.26,   541.26,    1.50)  DC

ALL       1ST HIGHEST VALUE IS    2252.97880 AT (  725600.00,  4547600.00,   529.76,   538.47,    1.50)  DC
          2ND HIGHEST VALUE IS    2251.61821 AT (  725200.00,  4547800.00,   515.95,   515.95,    1.50)  DC
          3RD HIGHEST VALUE IS    2243.83737 AT (  725600.00,  4547500.00,   532.57,   538.98,    1.50)  DC
          4TH HIGHEST VALUE IS    2232.95226 AT (  725700.00,  4547500.00,   536.35,   544.59,    1.50)  DC
          5TH HIGHEST VALUE IS    2231.48344 AT (  725500.00,  4547500.00,   529.38,   531.58,    1.50)  DC
          6TH HIGHEST VALUE IS    2231.48344 AT (  725500.00,  4547500.00,   529.38,   531.58,    1.50)  DC
          7TH HIGHEST VALUE IS    2222.24016 AT (  725500.00,  4547600.00,   523.69,   526.17,    1.50)  DC
          8TH HIGHEST VALUE IS    2211.54284 AT (  725700.00,  4547600.00,   533.10,   533.10,    1.50)  DC
          9TH HIGHEST VALUE IS    2202.41202 AT (  725400.00,  4547700.00,   518.95,   520.63,    1.50)  DC
         10TH HIGHEST VALUE IS    2190.80334 AT (  725800.00,  4547500.00,   541.26,   541.26,    1.50)  DC
```

```
*** AERMOD - VERSION  11103 ***   *** Shawville Plant - SO2 run 2 with 2010 acutal emissions  (AMI)        ***        08/19/11
                                   ***                                                     ***         14:00:03
                                                                                                      PAGE   6
           **MODELOPTs:  RegDFAULT CONC                                     ELEV      FLGPOL


                *** THE SUMMARY OF MAXIMUM   4TH-HIGHEST MAX DAILY  1-HR RESULTS AVERAGED OVER   1
                                                      YEARS ***


                                  ** CONC OF SO2       IN MICROGRAMS/M**3                       **

                                                                                                    NETWORK
GROUP ID                      AVERAGE CONC            RECEPTOR  (XR, YR, ZELEV, ZHILL, ZFLAG)  OF TYPE  GRID-ID
                 - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -

    U12       1ST HIGHEST VALUE IS     471.61067 AT (  715000.00,  4556600.00,   690.91,   690.91,    1.50)  DC
              2ND HIGHEST VALUE IS     467.56077 AT (  715100.00,  4556500.00,   686.30,   686.30,    1.50)  DC
              3RD HIGHEST VALUE IS     465.88261 AT (  715000.00,  4556500.00,   690.29,   690.29,    1.50)  DC
              4TH HIGHEST VALUE IS     465.88261 AT (  715000.00,  4556500.00,   690.29,   690.29,    1.50)  DC
              5TH HIGHEST VALUE IS     463.72014 AT (  715100.00,  4556600.00,   688.64,   688.64,    1.50)  DC
              6TH HIGHEST VALUE IS     461.69109 AT (  715100.00,  4556400.00,   682.00,   682.00,    1.50)  DC
              7TH HIGHEST VALUE IS     459.30861 AT (  714900.00,  4556600.00,   691.85,   691.85,    1.50)  DC
              8TH HIGHEST VALUE IS     459.10484 AT (  714700.00,  4555800.00,   676.20,   678.94,    1.50)  DC
              9TH HIGHEST VALUE IS     456.54254 AT (  713000.00,  4554700.00,   656.80,   656.80,    1.50)  DC
             10TH HIGHEST VALUE IS     455.88843 AT (  714700.00,  4555900.00,   681.55,   681.55,    1.50)  DC

    U34       1ST HIGHEST VALUE IS    1422.40388 AT (  725600.00,  4547100.00,   519.27,   519.27,    1.50)  DC
              2ND HIGHEST VALUE IS    1417.07626 AT (  725800.00,  4547500.00,   541.26,   541.26,    1.50)  DC
              3RD HIGHEST VALUE IS    1408.44711 AT (  725500.00,  4547100.00,   520.21,   520.21,    1.50)  DC
              4TH HIGHEST VALUE IS    1368.06569 AT (  725900.00,  4547500.00,   541.50,   545.65,    1.50)  DC
              5TH HIGHEST VALUE IS    1347.08237 AT (  725700.00,  4547000.00,   518.77,   518.77,    1.50)  DC
              6TH HIGHEST VALUE IS    1344.56137 AT (  726000.00,  4547400.00,   541.21,   541.21,    1.50)  DC
              7TH HIGHEST VALUE IS    1344.29001 AT (  725700.00,  4547600.00,   533.10,   533.10,    1.50)  DC
              8TH HIGHEST VALUE IS    1323.77882 AT (  725500.00,  4547200.00,   515.63,   518.97,    1.50)  DC
              9TH HIGHEST VALUE IS    1322.96136 AT (  725800.00,  4547000.00,   518.93,   518.93,    1.50)  DC
             10TH HIGHEST VALUE IS    1314.07207 AT (  726100.00,  4546800.00,   524.85,   524.85,    1.50)  DC

    ALL       1ST HIGHEST VALUE IS    1431.22558 AT (  725600.00,  4547100.00,   519.27,   519.27,    1.50)  DC
              2ND HIGHEST VALUE IS    1425.75531 AT (  725900.00,  4547500.00,   541.50,   545.65,    1.50)  DC
              3RD HIGHEST VALUE IS    1423.76688 AT (  725800.00,  4547500.00,   541.26,   541.26,    1.50)  DC
              4TH HIGHEST VALUE IS    1409.51602 AT (  725500.00,  4547100.00,   520.21,   520.21,    1.50)  DC
              5TH HIGHEST VALUE IS    1359.15595 AT (  725700.00,  4547600.00,   533.10,   533.10,    1.50)  DC
              6TH HIGHEST VALUE IS    1354.88268 AT (  726100.00,  4547400.00,   539.30,   539.30,    1.50)  DC
              7TH HIGHEST VALUE IS    1351.15690 AT (  726000.00,  4547400.00,   541.21,   541.21,    1.50)  DC
              8TH HIGHEST VALUE IS    1348.57592 AT (  725700.00,  4547000.00,   518.77,   518.77,    1.50)  DC
              9TH HIGHEST VALUE IS    1337.63640 AT (  726000.00,  4547500.00,   543.69,   547.52,    1.50)  DC
             10TH HIGHEST VALUE IS    1337.63640 AT (  726000.00,  4547500.00,   543.69,   547.52,    1.50)  DC


                                   *** RECEPTOR TYPES:  GC = GRIDCART
                                                        GP = GRIDPOLR
                                                        DC = DISCCART
                                                        DP = DISCPOLR
```

http://www.epa.gov/reg3artd/permitting/petitions3.htm
Last updated on Friday, February 11, 2011

Mid-Atlantic Air Protection

You are here: EPA Home EPA Permits EPA Air Permits Mid-Atlantic Air Protection Mid-Atlantic Air Permitting Title V Air Operating Permit Public Petition Deadlines

Title V Air Operating Permits Database Deadlines for Public Petitions to the Administrator for Permit Objections

A Title V air quality operating permit, issued to an air pollution source, specifies all Clean Air Act obligations such as:

- emissions limits
- monitoring
- recordkeeping
- reporting

These requirements are normally found in the State's air quality implementation plan (SIP), federal regulations and other permit conditions. This program provides an easier way for the source, States, EPA, and the public to better understand which requirements apply to each air pollution source and to know if the source is in compliance.

Under the Title V program, the public may petition EPA to object to a permit issued by a state agency provided they raised their objections to the state air agency:

- during the 30 day public comment period for the draft permit,
- before the expiration of EPA's 45 day review period, and
- EPA has not objected to the issuance of the permit.

If these conditions are met, anyone who raised objections during the public comment period may petition the EPA Administrator within 60 days of EPA's review period ending.

The table below lists proposed Title V permits submitted to EPA and undergoing EPA's 45 day review, including the start and expiration dates for EPA's 45 day review period. It also shows the start and expiration dates for the public's 60 day petition period following EPA's review period.

Tip: Click on a column heading to sort the records by that column.

State	**Facility Name**	**AIRS ID**	**Permit No.**	**EPA 45-day Review Period Start Date**	**EPA 45-day Review Period End Date**	**60-day Public Petition Period Start Date**	**60-day Public Petition Period End Date**	**Permit Action**
DC	WASHINGTON HOSPITAL CENTER	1100100014	NONE	02/10/2012	03/26/2012	03/27/2012	05/25/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
DE	DELAWARE SOLID WASTE-CHERRY ISLAND	1000300111	003-00111	03/08/2012	04/23/2012	04/24/2012	06/22/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
MD	JOHNS HOPKINS BAYVIEW HOSP.	NONE	24-510-1158	04/11/2012	05/25/2012	05/26/2012	07/24/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
MD	MONTGOMERY COUNTY RRF	24-031-01718	NONE	04/11/2012	05/25/2012	05/26/2012	07/24/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
MD	CANAM STEEL CORPORATION	24-021-00254	NONE	03/08/2012	04/23/2012	04/24/2012	06/22/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
MD	MIDSHORE II REGIONAL SOLID WASTE FACILITY	NONE	24-011-0109	03/05/2012	04/18/2012	04/19/2012	06/18/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	SAPA INDUSTRIAL EXTRUSIONS	42-107-00081	54-00022	05/12/2012	06/25/2012	06/26/2012	08/24/2012	INITIAL PERMIT ISSUANCE OR RENEWAL

PA	TEXAS EASTERN TRANS.-BEDFORD	NONE	05-05007	05/08/2012	06/21/2012	06/22/2012	08/20/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	NATIONAL FUEL GAS - ROYSTONE	NONE	62-00141	05/02/2012	06/15/2012	06/16/2012	08/14/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	PLASTIC DEV CO	23-2346740/01	41-00016	05/02/2012	06/15/2012	06/16/2012	08/14/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	GRAYMONT PA INC.	42-027-00041	42-027-00041	04/27/2012	06/11/2012	06/12/2012	08/10/2012	SIGNIFICANT PERMIT REVISION
PA	JERACO ENTERPRISES INC - MILTO	42-097-00214	49-00014	04/27/2012	06/11/2012	06/12/2012	08/10/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	ARKEMA INC (ALTUGLAS INT)	42-017-00319	09-00122	04/25/2012	06/08/2012	06/09/2012	08/07/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	FRES CO SYS USA INC	42-017-00225	09-00027	04/24/2012	06/07/2012	06/08/2012	08/06/2012	SIGNIFICANT PERMIT REVISION
PA	SUPERIOR GREENTREE LANFILL INC	25-1489499/01	24-00123	04/18/2012	06/01/2012	06/02/2012	07/31/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	ERIE WASTEWATER TREATMENT PLAN	NONE	NONE	04/12/2012	05/28/2012	05/29/2012	07/27/2012	SIGNIFICANT PERMIT REVISION
PA	JONES PERFORMANCE PRODUCTS	84-0886942/01	43-00287	04/12/2012	05/28/2012	05/29/2012	07/27/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	L & S SWEETENERS	NONE	36-05156	04/12/2012	05/28/2012	05/29/2012	07/27/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	GREEN GAS PIONEER CROSSING ENERGY LLC	NONE	06-05105	04/13/2012	05/28/2012	05/29/2012	07/27/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	EXELON GENERATION COMPANY - RICHMOND STATION	NONE	V11-003	03/29/2012	05/14/2012	05/15/2012	07/13/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	PECO RICHMOND STATION	4210104903	NONE	03/29/2012	05/14/2012	05/15/2012	07/13/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	ACCELLENT	42-091-00433	46099946	03/31/2012	05/14/2012	05/15/2012	07/13/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	FIBERMARK INC	42-017-00017	09-00028	03/31/2012	05/14/2012	05/15/2012	07/13/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	LORD CORP - IND PROD DIV	25-0626921/02	20-00123	03/26/2012	05/09/2012	05/10/2012	07/09/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	VEOLIA ENERGY (GRAYS FERRY COGEN)	4210104944	V11-014	03/20/2012	05/03/2012	05/04/2012	07/02/2012	INITIAL PERMIT ISSUANCE OR RENEWAL

PA	CONAGRA GROCERY PRODUCTS AKA IHFP	22-1577909/01	49-00002	03/15/2012	04/30/2012	05/01/2012	06/29/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	GREENVILLE METALS	42-085-00046	43-00011	03/16/2012	04/30/2012	05/01/2012	06/29/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	PGH CORNING - PORT ALLEGHENY	25-0729265/01	TV-42-00009	03/16/2012	04/30/2012	05/01/2012	06/29/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	PHILADELPHIA PRISON SYSTEM	4210109519	V11-035	03/12/2012	04/25/2012	04/26/2012	06/25/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	ELLWOOD NATIONAL FORGE	NONE	62-0032I	03/05/2012	04/18/2012	04/19/2012	06/18/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	DEL MONTE CORP	42-037-00010	19-00006	03/01/2012	04/16/2012	04/17/2012	06/15/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	AK STEEL BUTLER	42-019-00001	10-0001	02/29/2012	04/13/2012	04/14/2012	06/12/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	ALCOA COMMERCIAL WINDOWS LLC	25-1071830/01	10-00267	02/28/2012	04/12/2012	04/13/2012	06/11/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	FRES CO SYS USA INC	42-017-00225	09-00027	02/25/2012	04/09/2012	04/10/2012	06/08/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	US STEEL CORPORATION, CLAIRTON WORKS	NONE	0052	02/22/2012	04/06/2012	04/07/2012	06/05/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	GENON REMA SHAWVILLE	42-033-00001	17-00001	02/13/2012	03/28/2012	03/29/2012	05/28/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	EME HOMER CITY GEN LP	42-063-00002	32-00055H	02/09/2012	03/26/2012	03/27/2012	05/25/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	ROHM AND HASS CO./BRISTOL	42-017-00019	09-00015	05/19/2012	07/02/2012	07/03/2012	08/31/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	EXELON GEN-CROMBY STATION	42-029-00003	15-00019	05/16/2012	06/29/2012	06/30/2012	08/28/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	PA DEPT OF CORRECTIONS - GRATERFORD	42-091-0008	46-00061	05/16/2012	06/29/2012	06/30/2012	08/28/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
PA	BUCKEYE PIPELINE MALVERN	42-029-00034	15-00105	05/12/2012	06/25/2012	06/26/2012	08/24/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
VA	MASTERBRAND CABINETS, INC.	51-089-00132	BRRO-21432	04/18/2012	06/01/2012	06/02/2012	07/31/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
								INITIAL

VA	INGENCO - DINWIDDIE	510530087	PRO-51083	04/11/2012	05/25/2012	05/26/2012	07/24/2012	PERMIT ISSUANCE OR RENEWAL
VA	LYON SHIPYARD	51-710-0249	NONE	04/09/2012	05/23/2012	05/24/2012	07/23/2012	SIGNIFICANT PERMIT REVISION
VA	US NAVY NORFOLK NAVAL BASE SEWELLS POINT	51-710-0194	NONE	04/09/2012	05/23/2012	05/24/2012	07/23/2012	SIGNIFICANT PERMIT REVISION
VA	E. I. DUPONT - SPRUANCE PLANT (VIRGINIA)	51-041-0001	PRO-50397		05/18/2012	05/19/2012	07/17/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
VA	TRANSMONTAIGNE OPER CO,- FAIRFAX TERMINAL	51-059-0082	NRO-70306	03/23/2012	05/07/2012	05/08/2012	07/06/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
VA	TRANSMONTAIGNE OPER CO.- FAIRFAX TERMINAL	51-059-0082	NRO-70306	03/23/2012	05/07/2012	05/08/2012	07/06/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
VA	BATTLE CREEK LANDFILL	511390031	VRO-81380	03/02/2012	04/16/2012	04/17/2012	06/15/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
VA	INTERNATIONAL PAPER - FINE PAPER - FRANKLIN MILL VIRGINIA	510930006	TRO-60214	03/02/2012	04/16/2012	04/17/2012	06/15/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	UNION CARBIDE CORP SO. CHARLESTON PLANT	5403900003	R30039000032012	05/11/2012	06/25/2012	06/26/2012	08/24/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	MPM SILICONES [FORMERLY -GE SILICONES] SISTERVILLE PLANT	5409500001	R30095000012012	05/09/2012	06/22/2012	06/23/2012	08/21/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	SMR TECHNOLOGIES INC	54-067-00025	R30067000252012	05/03/2012	06/18/2012	06/19/2012	08/17/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	UNION CARBIDE CORP INSTITUTE PLT GRP 5 OF 5	540390005	R30039000052O12	04/26/2012	06/11/2012	06/12/2012	08/10/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	BAYER MATERIAL SCIENCE LLC - SO CHARLESTON PLANT	5403900102	R30039001022012	04/23/2012	06/06/2012	06/07/2012	08/06/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	SABIC INNOVATIVE PLASTICS (ENTIRE TITLE V PERMIT)	5410700010	R30107000102012	04/20/2012	06/04/2012	06/05/2012	08/03/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	DOMINION TRANSMISSION - SWEENEY COMPRESSOR STATION R1	54-041-00012	R30041000122012	04/18/2012	06/01/2012	06/02/2012	07/31/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	ASHLAND INC NEAL PLANT	54-099-00009	NONE	04/04/2012	05/18/2012	05/19/2012	07/17/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	CRANBERRY PIPELINE- BRADLEY STATION	54-109-00017	R30109000172012	03/28/2012	05/11/2012	05/12/2012	07/10/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
	PPG INDUSTRIES,							INITIAL

WV	INC. NATRIUM PLANT	5405100002	R30051000022012	03/26/2012	05/09/2012	05/10/2012	07/09/2012	PERMIT ISSUANCE OR RENEWAL
WV	UNION CARBIDE CORP INSTITUTE PLT GRP 3 OF 5	5403900005	NONE	03/27/2012	05/10/2012	05/11/2012	07/09/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	GRAFTECH INTERNATIONAL HOLDINGS	5403300001	R30033000012012	03/16/2012	04/30/2012	05/01/2012	06/29/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	BRASKEM NEAL PLANT	5409900010	R30099000102012	03/07/2012	04/20/2012	04/21/2012	06/19/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	E.I. DUPONT DE NEMOURS (PART 10 OF 14)	541070001	R3010700001	03/02/2012	04/16/2012	04/17/2012	06/15/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	QUAD GRAPHICS	54-003-00042	NONE	02/22/2012	04/06/2012	04/07/2012	06/05/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	SECOND STERLING NO.1 COAL PREP. PLANT	54-047-00008	R30047000082012	02/22/2012	04/06/2012	04/07/2012	06/05/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	ARDAGH METAL PACKING GROUP USA WEIRTON PLANT	54-009-00012	R30009000122012	02/17/2012	04/02/2012	04/03/2012	06/01/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	CYTEC INDUSTRIES (2 OF 4)	54-073-00003	R30073000032012	02/15/2012	03/30/2012	03/31/2012	05/29/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	UNION CARBIDE CORP INSTITUTE PLT GRP 4 OF 5	5403900005	R30039000052012	02/13/2012	03/28/2012	03/29/2012	05/28/2012	INITIAL PERMIT ISSUANCE OR RENEWAL
WV	CROWN CORK & SEAL CO. WEIRTON PLANT	54-009-00014	R30009000142012	02/10/2012	03/26/2012	03/27/2012	05/25/2012	INITIAL PERMIT ISSUANCE OR RENEWAL

Please note that the above information is derived from the EPA Region 3 Title V database. It is recommended that data for permits of particular interest be confirmed with EPA Region 3. Please contact Kathleen Cox at 215-814-2173, cox.kathleen@epa.gov.

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR QUALITY PROGRAM

TITLE V/STATE OPERATING PERMIT

Issue Date: March 26, 2012
Effective Date: March 26, 2012
Expiration Date: March 25, 2017

In accordance with the provisions of the Air Pollution Control Act, the Act of January 8, 1960, P.L. 2119, as amended, and 25 Pa. Code Chapter 127, the Owner, [and Operator if noted] (hereinafter referred to as permittee) identified below is authorized by the Department of Environmental Protection (Department) to operate the air emission source(s) more fully described in this permit. This Facility is subject to all terms and conditions specified in this permit. Nothing in this permit relieves the permittee from its obligations to comply with all applicable Federal, State and Local laws and regulations.

The regulatory or statutory authority for each permit condition is set forth in brackets. All terms and conditions in this permit are federally enforceable applicable requirements unless otherwise designated as "State-Only" or "non-applicable" requirements.

TITLE V Permit No: 17-00001

Federal Tax Id - Plant Code: 52-2154847-3

Owner Information

Name: GENON REMA, LLC
Mailing Address: 121 CHAMPION WAY STE 200
CANONSBURG, PA 15317-5817

Plant Information

Plant: GENON REMA LLC/SHAWVILLE GEN STA
Location: 17 Clearfield County 17909 Bradford Township
SIC Code: 4911 Trans. & Utilities - Electric Services

Responsible Official

Name: LEO C RAJTER
Title: VICE PRESIDENT OPERATIONS
Phone: (717) 338 - 3511

Permit Contact Person

Name: TIMOTHY E MCKENZIE
Title: SR ENV SCIENTIST
Phone: (724) 597 - 8670

[Signature] Muhammad Q. Zaman
MUHAMMAD Q. ZAMAN, ENVIRONMENTAL PROGRAM MANAGER, NORTHCENTRAL REGION

SECTION A. Table of Contents

Note: These same sub-sections are repeated for each source!

SECTION A. Table of Contents

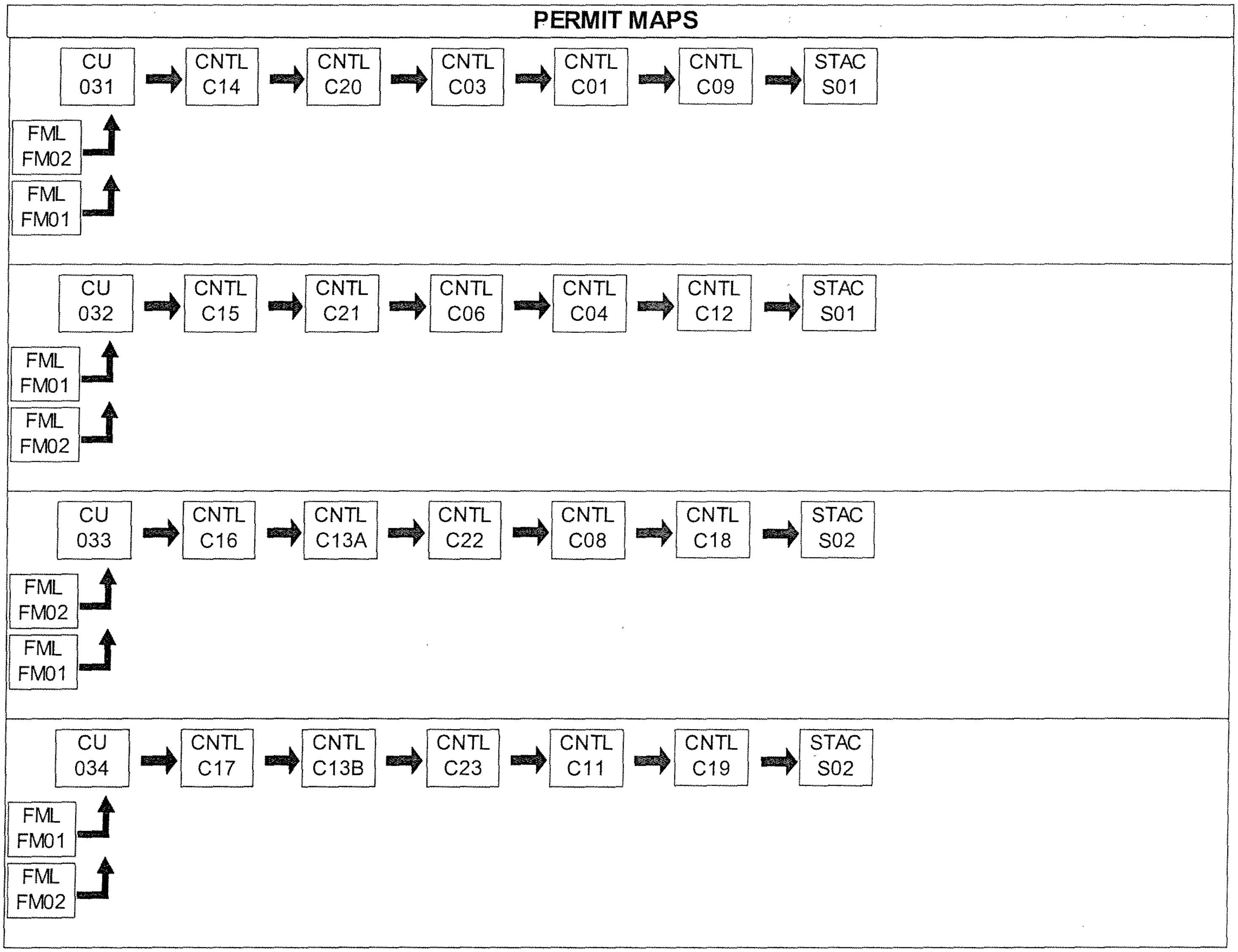
SECTION A. Site Inventory List

Source ID	Source Name	Capacity/Throughput		Fuel/Material
031	UTILITY BOILER - UNIT 1	1,345.000	MMBTU/HR	
032	UTILITY BOILER - UNIT 2	1,345.000	MMBTU/HR	
033	UTILITY BOILER - UNIT 3	1,790.000	MMBTU/HR	
034	UTILITY BOILER - UNIT 4	1,790.000	MMBTU/HR	
038	15 SPACE HEATERS			
F01	PLANT HAUL ROADS			
F02	COAL HANDLING AND STORAGE			
F03	ASH DISPOSAL FACILITY			
P101	STARTUP GENERATOR 5			
P102	STARTUP GENERATOR 6			
P103	STARTUP GENERATOR 7			
P104	EMERGENCY GENERATOR 1(UNIT 1-2)			
P106	2 FIRE PUMP ENGINES			
P116	WATER TREATMENT OPERATIONS			
P120	EMERGENCY DIESEL GENERATOR			
P121	PARTS WASHERS			
C01	RESEARCH COTTRELL ESP-UNIT 1			
C03	NH3/SO3 INJECTION FLUE GAS-UNIT 1			
C04	RESEARCH COTTRELL ESP-UNIT 2			
C06	NH3/SO3 INJECTION FLUE GAS-UNIT 2			
C08	RESEARCH COTTRELL ESP-UNIT 3			
C09	BUELL ESP-UNIT 1			
C11	RESEARCH COTTRELL ESP-UNIT 4			
C12	BUELL ESP-UNIT 2			
C13A	OVERFIRE AIR-UNIT 3			
C13B	OVERFIRE AIR-UNIT 4			
C14	LOW NOX BURNERS-UNIT 1			
C15	LOW NOX BURNERS-UNIT 2			
C16	LOW NOX BURNER-UNIT 3			
C17	LOW NOX BURNERS-UNIT 4			
C18	BUELL ESP-UNIT 3			
C19	BUELL ESP-UNIT 4			
C20	SNCR 1			
C21	SNCR 2			
C22	SNCR 3			
C23	SNCR 4			
FM01	COAL/SYNFUEL STOCKPLE			
FM02	OIL STORAGE TANKS			
FM03	DIESEL STORAGE			
S01	UNITS 1 & 2 STACK			

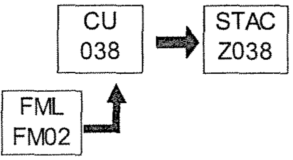
SECTION A. Site Inventory List

Source ID	Source Name	Capacity/Throughput	Fuel/Material
S02	UNITS 3 & 4 STACK		
S03	GENERATOR 5 STACK		
S06	EMERGENCY GEN 1 STACK		
S120	GENERATOR STACK		
S13	GENERATOR 6 STACK		
S23	GENERATOR 7 STACK		
SO8	FIRE PUMP ENGINE STACK		
Z01	HAUL ROAD EMISSIONS		
Z02	COAL HANDLING EMISSIONS		
Z03	ASH DISPOSAL EMISSIONS		
Z038	FUGITIVE EMISSIONS		
Z116	WATERTREATMENT EMISSIONS		
Z121	PARTS WASHER EMISSIONS		

PERMIT MAPS



PERMIT MAPS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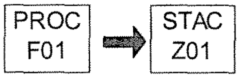
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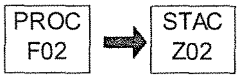
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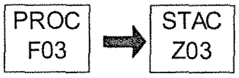
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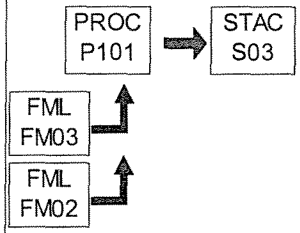
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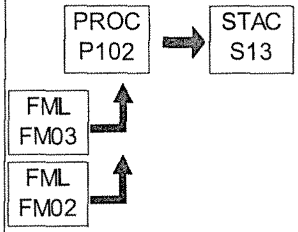
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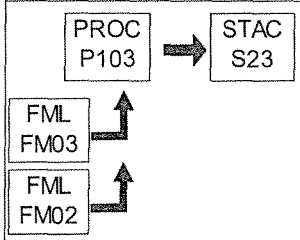
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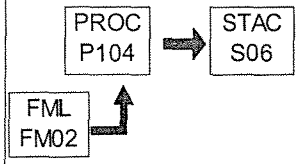
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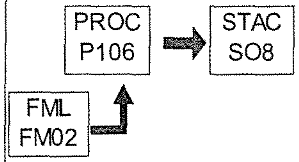
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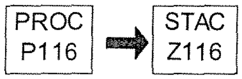
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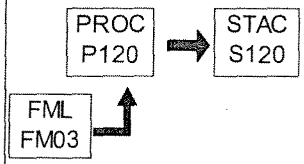
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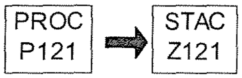
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SECTION B. General Title V Requirements

#001 [25 Pa. Code § 121.1]

Definitions

Words and terms that are not otherwise defined in this permit shall have the meanings set forth in Section 3 of the Air Pollution Control Act (35 P.S. § 4003) and 25 Pa. Code § 121.1.

#002 [25 Pa. Code § 127.512(c)(4)]

Property Rights

This permit does not convey property rights of any sort, or any exclusive privileges.

#003 [25 Pa. Code § 127.446(a) and (c)]

Permit Expiration

This operating permit is issued for a fixed term of five (5) years and shall expire on the date specified on Page 1 of this permit. The terms and conditions of the expired permit shall automatically continue pending issuance of a new Title V permit, provided the permittee has submitted a timely and complete application and paid applicable fees required under 25 Pa. Code Chapter 127, Subchapter I and the Department is unable, through no fault of the permittee, to issue or deny a new permit before the expiration of the previous permit. An application is complete if it contains sufficient information to begin processing the application, has the applicable sections completed and has been signed by a responsible official.

#004 [25 Pa. Code §§ 127.412, 127.413, 127.414, 127.446(e) & 127.503]

Permit Renewal

(a) An application for the renewal of the Title V permit shall be submitted to the Department at least six (6) months, and not more than 18 months, before the expiration date of this permit. The renewal application is timely if a complete application is submitted to the Department's Regional Air Manager within the timeframe specified in this permit condition.

(b) The application for permit renewal shall include the current permit number, the appropriate permit renewal fee, a description of any permit revisions and off-permit changes that occurred during the permit term, and any applicable requirements that were promulgated and not incorporated into the permit during the permit term.

(c) The renewal application shall also include submission of proof that the local municipality and county, in which the facility is located, have been notified in accordance with 25 Pa. Code § 127.413. The application for renewal of the Title V permit shall also include submission of compliance review forms which have been used by the permittee to update information submitted in accordance with either 25 Pa. Code § 127.412(b) or § 127.412(j).

(d) The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall submit such supplementary facts or corrected information during the permit renewal process. The permittee shall also provide additional information as necessary to address any requirements that become applicable to the source after the date a complete renewal application was submitted but prior to release of a draft permit.

#005 [25 Pa. Code §§ 127.450(a)(4) & 127.464(a)]

Transfer of Ownership or Operational Control

(a) In accordance with 25 Pa. Code § 127.450(a)(4), a change in ownership or operational control of the source shall be treated as an administrative amendment if:

(1) The Department determines that no other change in the permit is necessary;

(2) A written agreement has been submitted to the Department identifying the specific date of the transfer of permit responsibility, coverage and liability between the current and the new permittee; and,

(3) A compliance review form has been submitted to the Department and the permit transfer has been approved by the Department.

(b) In accordance with 25 Pa. Code § 127.464(a), this permit may not be transferred to another person except in cases of transfer-of-ownership which are documented and approved to the satisfaction of the Department.

#006 [25 Pa. Code § 127.513, 35 P.S. § 4008 and § 114 of the CAA]

Inspection and Entry

(a) Upon presentation of credentials and other documents as may be required by law for inspection and entry purposes, the permittee shall allow the Department of Environmental Protection or authorized representatives of the Department to perform the following:

(1) Enter at reasonable times upon the permittee's premises where a Title V source is located or emissions related activity is conducted, or where records are kept under the conditions of this permit;

(2) Have access to and copy or remove, at reasonable times, records that are kept under the conditions of this permit;

(3) Inspect at reasonable times, facilities, equipment including monitoring and air pollution control equipment, practices, or operations regulated or required under this permit;

(4) Sample or monitor, at reasonable times, substances or parameters, for the purpose of assuring compliance with the permit or applicable requirements as authorized by the Clean Air Act, the Air Pollution Control Act, or the regulations promulgated under the Acts.

(b) Pursuant to 35 P.S. § 4008, no person shall hinder, obstruct, prevent or interfere with the Department or its personnel in the performance of any duty authorized under the Air Pollution Control Act.

(c) Nothing in this permit condition shall limit the ability of the EPA to inspect or enter the premises of the permittee in accordance with Section 114 or other applicable provisions of the Clean Air Act.

#007 [25 Pa. Code §§ 127.25, 127.444, & 127.512(c)(1)]

Compliance Requirements

(a) The permittee shall comply with the conditions of this permit. Noncompliance with this permit constitutes a violation of the Clean Air Act and the Air Pollution Control Act and is grounds for one (1) or more of the following:

(1) Enforcement action

(2) Permit termination, revocation and reissuance or modification

(3) Denial of a permit renewal application

(b) A person may not cause or permit the operation of a source, which is subject to 25 Pa. Code Article III, unless the source(s) and air cleaning devices identified in the application for the plan approval and operating permit and the plan approval issued to the source are operated and maintained in accordance with specifications in the applications and the conditions in the plan approval and operating permit issued by the Department. A person may not cause or permit the operation of an air contamination source subject to 25 Pa. Code Chapter 127 in a manner inconsistent with good operating practices.

(c) For purposes of Sub-condition (b) of this permit condition, the specifications in applications for plan approvals and operating permits are the physical configurations and engineering design details which the Department determines are essential for the permittee's compliance with the applicable requirements in this Title V permit. Nothing in this sub-condition shall be construed to create an independent affirmative duty upon the permittee to obtain a predetermination from the Department for physical configuration or engineering design detail changes made by the permittee.

#008 [25 Pa. Code § 127.512(c)(2)]

Need to Halt or Reduce Activity Not a Defense

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 in order to maintain compliance with the conditions of this permit.

SECTION B. General Title V Requirements

#009 [25 Pa. Code §§ 127.411(d) & 127.512(c)(5)]

Duty to Provide Information

(a) The permittee shall furnish to the Department, within a reasonable time, information that the Department 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.

(b) Upon request, the permittee shall also furnish to the Department copies of records that the permittee is required to keep by this permit, or for information claimed to be confidential, the permittee may furnish such records directly to the Administrator of EPA along with a claim of confidentiality.

#010 [25 Pa. Code §§ 127.463, 127.512(c)(3) & 127.542]

Reopening and Revising the Title V Permit for Cause

(a) This Title V permit may be modified, revoked, reopened and reissued or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay a permit condition.

(b) This permit may be reopened, revised and reissued prior to expiration of the permit under one or more of the following circumstances:

(1) Additional applicable requirements under the Clean Air Act or the Air Pollution Control Act become applicable to a Title V facility with a remaining permit term of three (3) or more years prior to the expiration date of this permit. The Department will revise the permit as expeditiously as practicable but not later than 18 months after promulgation of the applicable standards or regulations. No such revision is required if the effective date of the requirement is later than the expiration date of this permit, unless the original permit or its terms and conditions has been extended.

(2) Additional requirements, including excess emissions requirements, become applicable to an affected source under the acid rain program. Upon approval by the Administrator of EPA, excess emissions offset plans for an affected source shall be incorporated into the permit.

(3) The Department or the EPA determines that this permit contains a material mistake or inaccurate statements were made in establishing the emissions standards or other terms or conditions of this permit.

(4) The Department or the Administrator of EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

(c) Proceedings to revise this permit shall follow the same procedures which apply to initial permit issuance and shall affect only those parts of this permit for which cause to revise exists. The revision shall be made as expeditiously as practicable.

(d) Regardless of whether a revision is made in accordance with (b)(1) above, the permittee shall meet the applicable standards or regulations promulgated under the Clean Air Act within the time frame required by standards or regulations.

#011 [25 Pa. Code § 127.543]

Reopening a Title V Permit for Cause by EPA

As required by the Clean Air Act and regulations adopted thereunder, this permit may be modified, reopened and reissued, revoked or terminated for cause by EPA in accordance with procedures specified in 25 Pa. Code § 127.543.

#012 [25 Pa. Code § 127.541]

Significant Operating Permit Modifications

When permit modifications during the term of this permit do not qualify as minor permit modifications or administrative amendments, the permittee shall submit an application for significant Title V permit modifications in accordance with 25 Pa. Code § 127.541.

SECTION B. General Title V Requirements

#013 [25 Pa. Code §§ 121.1 & 127.462]

Minor Operating Permit Modifications

(a) The permittee may make minor operating permit modifications (as defined in 25 Pa. Code § 121.1) in accordance with 25 Pa. Code § 127.462.

(b) Unless precluded by the Clean Air Act or the regulations thereunder, the permit shield described in 25 Pa. Code § 127.516 (relating to permit shield) shall extend to an operational flexibility change authorized by 25 Pa. Code § 127.462.

#014 [25 Pa. Code § 127.450]

Administrative Operating Permit Amendments

(a) The permittee may request administrative operating permit amendments, as defined in 25 Pa. Code § 127.450(a), according to procedures specified in § 127.450. Administrative amendments are not authorized for any amendment precluded by the Clean Air Act or the regulations thereunder from being processed as an administrative amendment.

(b) Upon taking final action granting a request for an administrative permit amendment in accordance with § 127.450(c), the Department will allow coverage under 25 Pa. Code § 127.516 (relating to permit shield) for administrative permit amendments which meet the relevant requirements of 25 Pa. Code Article III, unless precluded by the Clean Air Act or the regulations thereunder.

#015 [25 Pa. Code § 127.512(b)]

Severability Clause

The provisions of this permit are severable, and if any provision of this permit is determined by the Environmental Hearing Board or a court of competent jurisdiction to be invalid or unenforceable, such a determination will not affect the remaining provisions of this permit.

#016 [25 Pa. Code §§ 127.704, 127.705 & 127.707]

Fee Payment

(a) The permittee shall pay fees to the Department in accordance with the applicable fee schedules in 25 Pa. Code Chapter 127, Subchapter I (relating to plan approval and operating permit fees).

(b) Emission Fees. The permittee shall, on or before September 1st of each year, pay applicable annual Title V emission fees for emissions occurring in the previous calendar year as specified in 25 Pa. Code § 127.705. The permittee is not required to pay an emission fee for emissions of more than 4,000 tons of each regulated pollutant emitted from the facility.

(c) As used in this permit condition, the term "regulated pollutant" is defined as a VOC, each pollutant regulated under Sections 111 and 112 of the Clean Air Act and each pollutant for which a National Ambient Air Quality Standard has been promulgated, except that carbon monoxide is excluded.

(d) Late Payment. Late payment of emission fees will subject the permittee to the penalties prescribed in 25 Pa. Code § 127.707 and may result in the suspension or termination of the Title V permit. The permittee shall pay a penalty of fifty percent (50%) of the fee amount, plus interest on the fee amount computed in accordance with 26 U.S.C.A. § 6621(a)(2) from the date the emission fee should have been paid in accordance with the time frame specified in 25 Pa. Code § 127.705(c).

(e) The permittee shall pay an annual operating permit administration fee according to the fee schedule established in 25 Pa. Code § 127.704(c) if the facility, identified in Subparagraph (iv) of the definition of the term "Title V facility" in 25 Pa. Code § 121.1, is subject to Title V after the EPA Administrator completes a rulemaking requiring regulation of those sources under Title V of the Clean Air Act.

(f) This permit condition does not apply to a Title V facility which qualifies for exemption from emission fees under 35 P.S. § 4006.3(f).

#017 [25 Pa. Code §§ 127.14(b) & 127.449]

Authorization for De Minimis Emission Increases

(a) This permit authorizes de minimis emission increases from a new or existing source in accordance with 25 Pa. Code §§ 127.14 and 127.449 without the need for a plan approval or prior issuance of a permit modification. The permittee shall provide the Department with seven (7) days prior written notice before commencing any de minimis emissions increase that would result from either: (1) a physical change of minor significance under § 127.14(c)(1); or (2) the construction, installation, modification or reactivation of an air contamination source. The written notice shall:

(1) Identify and describe the pollutants that will be emitted as a result of the de minimis emissions increase.

(2) Provide emission rates expressed in tons per year and in terms necessary to establish compliance consistent with any applicable requirement.

The Department may disapprove or condition de minimis emission increases at any time.

(b) Except as provided below in (c) and (d) of this permit condition, the permittee is authorized during the term of this permit to make de minimis emission increases (expressed in tons per year) up to the following amounts without the need for a plan approval or prior issuance of a permit modification:

(1) Four tons of carbon monoxide from a single source during the term of the permit and 20 tons of carbon monoxide at the facility during the term of the permit.

(2) One ton of NOx from a single source during the term of the permit and 5 tons of NOx at the facility during the term of the permit.

(3) One and six-tenths tons of the oxides of sulfur from a single source during the term of the permit and 8.0 tons of oxides of sulfur at the facility during the term of the permit.

(4) Six-tenths of a ton of PM10 from a single source during the term of the permit and 3.0 tons of PM10 at the facility during the term of the permit. This shall include emissions of a pollutant regulated under Section 112 of the Clean Air Act unless precluded by the Clean Air Act or 25 Pa. Code Article III.

(5) One ton of VOCs from a single source during the term of the permit and 5.0 tons of VOCs at the facility during the term of the permit. This shall include emissions of a pollutant regulated under Section 112 of the Clean Air Act unless precluded by the Clean Air Act or 25 Pa. Code Article III.

(c) In accordance with § 127.14, the permittee may install the following minor sources without the need for a plan approval:

(1) Air conditioning or ventilation systems not designed to remove pollutants generated or released from other sources.

(2) Combustion units rated at 2,500,000 or less Btu per hour of heat input.

(3) Combustion units with a rated capacity of less than 10,000,000 Btu per hour heat input fueled by natural gas supplied by a public utility, liquefied petroleum gas or by commercial fuel oils which are No. 2 or lighter, viscosity less than or equal to 5.82 c St, and which meet the sulfur content requirements of 25 Pa. Code § 123.22 (relating to combustion units). For purposes of this permit, commercial fuel oil shall be virgin oil which has no reprocessed, recycled or waste material added.

(4) Space heaters which heat by direct heat transfer.

(5) Laboratory equipment used exclusively for chemical or physical analysis.

(6) Other sources and classes of sources determined to be of minor significance by the Department.

(d) This permit does not authorize de minimis emission increases if the emissions increase would cause one or more of the following:

(1) Increase the emissions of a pollutant regulated under Section 112 of the Clean Air Act except as authorized in Subparagraphs (b)(4) and (5) of this permit condition.

(2) Subject the facility to the prevention of significant deterioration requirements in 25 Pa. Code Chapter 127, Subchapter D and/or the new source review requirements in Subchapter E.

(3) Violate any applicable requirement of the Air Pollution Control Act, the Clean Air Act, or the regulations promulgated under either of the acts.

(4) Changes which are modifications under any provision of Title I of the Clean Air Act and emission increases which would exceed the allowable emissions level (expressed as a rate of emissions or in terms of total emissions) under the Title V permit.

(e) Unless precluded by the Clean Air Act or the regulations thereunder, the permit shield described in 25 Pa. Code § 127.516 (relating to permit shield) applies to de minimis emission increases and the installation of minor sources made pursuant to this permit condition.

(f) Emissions authorized under this permit condition shall be included in the monitoring, recordkeeping and reporting requirements of this permit.

(g) Except for de minimis emission increases allowed under this permit, 25 Pa. Code § 127.449, or sources and physical changes meeting the requirements of 25 Pa. Code § 127.14, the permittee is prohibited from making physical changes or engaging in activities that are not specifically authorized under this permit without first applying for a plan approval. In accordance with § 127.14(b), a plan approval is not required for the construction, modification, reactivation, or installation of the sources creating the de minimis emissions increase.

(h) The permittee may not meet de minimis emission threshold levels by offsetting emission increases or decreases at the same source.

#018 [25 Pa. Code §§ 127.11a & 127.215]

Reactivation of Sources

(a) The permittee may reactivate a source at the facility that has been out of operation or production for at least one year, but less than or equal to five (5) years, if the source is reactivated in accordance with the requirements of 25 Pa. Code §§ 127.11a and 127.215. The reactivated source will not be considered a new source.

(b) A source which has been out of operation or production for more than five (5) years but less than 10 years may be reactivated and will not be considered a new source if the permittee satisfies the conditions specified in 25 Pa. Code § 127.11a(b).

#019 [25 Pa. Code §§ 121.9 & 127.216]

Circumvention

(a) The owner of this Title V facility, or any other person, may not circumvent the new source review requirements of 25 Pa. Code Chapter 127, Subchapter E by causing or allowing a pattern of ownership or development, including the phasing, staging, delaying or engaging in incremental construction, over a geographic area of a facility which, except for the pattern of ownership or development, would otherwise require a permit or submission of a plan approval application.

(b) No person may permit the use of a device, stack height which exceeds good engineering practice stack height, dispersion technique or other technique which, without resulting in reduction of the total amount of air contaminants emitted, conceals or dilutes an emission of air contaminants which would otherwise be in violation of this permit, the Air Pollution Control Act or the regulations promulgated thereunder, except that with prior approval of the Department, the device or technique may be used for control of malodors.

SECTION B. General Title V Requirements

#020 [25 Pa. Code §§ 127.402(d) & 127.513(1)]
Submissions

(a) Reports, test data, monitoring data, notifications and requests for renewal of the permit shall be submitted to the:

Regional Air Program Manager
PA Department of Environmental Protection
(At the address given on the permit transmittal letter,
or otherwise notified)

(b) Any report or notification for the EPA Administrator or EPA Region III should be addressed to:

Office of Air Enforcement and Compliance Assistance (3AP20)
United States Environmental Protection Agency
Region 3
1650 Arch Street
Philadelphia, PA 19103-2029

(c) An application, form, report or compliance certification submitted pursuant to this permit condition shall contain certification by a responsible official as to truth, accuracy, and completeness as required under 25 Pa. Code § 127.402(d). Unless otherwise required by the Clean Air Act or regulations adopted thereunder, this certification and any other certification required pursuant to this permit shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

#021 [25 Pa. Code §§ 127.441(c) & 127.463(e); Chapter 139; & 114(a)(3), 504(b) of the CAA]
Sampling, Testing and Monitoring Procedures

(a) The permittee shall perform the emissions monitoring and analysis procedures or test methods for applicable requirements of this Title V permit. In addition to the sampling, testing and monitoring procedures specified in this permit, the Permittee shall comply with any additional applicable requirements promulgated under the Clean Air Act after permit issuance regardless of whether the permit is revised.

(b) The sampling, testing and monitoring required under the applicable requirements of this permit, shall be conducted in accordance with the requirements of 25 Pa. Code Chapter 139 unless alternative methodology is required by the Clean Air Act (including §§ 114(a)(3) and 504(b)) and regulations adopted thereunder.

#022 [25 Pa. Code §§ 127.511 & Chapter 135]
Recordkeeping Requirements

(a) The permittee shall maintain and make available, upon request by the Department, records of required monitoring information that include the following:

(1) The date, place (as defined in the permit) and time of sampling or measurements.

(2) The dates the analyses were performed.

(3) The company or entity that performed the analyses.

(4) The analytical techniques or methods used.

(5) The results of the analyses.

(6) The operating conditions as existing at the time of sampling or measurement.

(b) The permittee shall retain records of the required monitoring data and supporting information for at least five (5) years from the date of the monitoring sample, measurement, report or application. Supporting information includes the calibration data and maintenance records and original strip-chart recordings for continuous monitoring instrumentation, and copies of reports required by the permit.

(c) The permittee shall maintain and make available to the Department upon request, records including computerized records that may be necessary to comply with the reporting, recordkeeping and emission statement requirements in 25 Pa. Code Chapter 135 (relating to reporting of sources). In accordance with 25 Pa. Code Chapter 135, § 135.5, such records may include records of production, fuel usage, maintenance of production or pollution control equipment or other information determined by the Department to be necessary for identification and quantification of potential and actual air contaminant emissions. If direct recordkeeping is not possible or practical, sufficient records shall be kept to provide the needed information by indirect means.

#023 [25 Pa. Code §§ 127.411(d), 127.442, 127.463(e) & 127.511(c)]

Reporting Requirements

(a) The permittee shall comply with the reporting requirements for the applicable requirements specified in this Title V permit. In addition to the reporting requirements specified herein, the permittee shall comply with any additional applicable reporting requirements promulgated under the Clean Air Act after permit issuance regardless of whether the permit is revised.

(b) Pursuant to 25 Pa. Code § 127.511(c), the permittee shall submit reports of required monitoring at least every six (6) months unless otherwise specified in this permit. Instances of deviations (as defined in 25 Pa. Code § 121.1) from permit requirements shall be clearly identified in the reports. The reporting of deviations shall include the probable cause of the deviations and corrective actions or preventative measures taken, except that sources with continuous emission monitoring systems shall report according to the protocol established and approved by the Department for the source. The required reports shall be certified by a responsible official.

(c) Every report submitted to the Department under this permit condition shall comply with the submission procedures specified in Section B, Condition #020(c) of this permit.

(d) Any records, reports or information obtained by the Department or referred to in a public hearing shall be made available to the public by the Department except for such records, reports or information for which the permittee has shown cause that the documents should be considered confidential and protected from disclosure to the public under Section 4013.2 of the Air Pollution Control Act and consistent with Sections 112(d) and 114(c) of the Clean Air Act and 25 Pa. Code § 127.411(d). The permittee may not request a claim of confidentiality for any emissions data generated for the Title V facility.

#024 [25 Pa. Code § 127.513]

Compliance Certification

(a) One year after the date of issuance of the Title V permit, and each year thereafter, unless specified elsewhere in the permit, the permittee shall submit to the Department and EPA Region III a certificate of compliance with the terms and conditions in this permit, for the previous year, including the emission limitations, standards or work practices. This certification shall include:

(1) The identification of each term or condition of the permit that is the basis of the certification.

(2) The compliance status.

(3) The methods used for determining the compliance status of the source, currently and over the reporting period.

(4) Whether compliance was continuous or intermittent.

(b) The compliance certification should be postmarked or hand-delivered within thirty days of each anniversary date of the date of issuance or, of the submittal date specified elsewhere in the permit, to the Department and EPA in accordance with the submission requirements specified in condition #020 of this section.

#025 [25 Pa. Code § 127.3]

Operational Flexibility

(a) The permittee is authorized to make changes within the Title V facility in accordance with the following provisions in 25 Pa. Code Chapter 127 which implement the operational flexibility requirements of Section 502(b)(10) of the Clean Air Act and Section 6.1(i) of the Air Pollution Control Act:

(1) Section 127.14 (relating to exemptions)

(2) Section 127.447 (relating to alternative operating scenarios)

(3) Section 127.448 (relating to emissions trading at facilities with Federally enforceable emissions caps)

(4) Section 127.449 (relating to de minimis emission increases)

(5) Section 127.450 (relating to administrative operating permit amendments)

(6) Section 127.462 (relating to minor operating permit amendments)

(7) Subchapter H (relating to general plan approvals and operating permits)

(b) Unless precluded by the Clean Air Act or the regulations adopted thereunder, the permit shield authorized under 25 Pa. Code § 127.516 shall extend to operational flexibility changes made at this Title V facility pursuant to this permit condition and other applicable operational flexibility terms and conditions of this permit.

#026 [25 Pa. Code §§ 127.441(d), 127.512(i) and 40 CFR Part 68]
Risk Management

(a) If required by Section 112(r) of the Clean Air Act, the permittee shall develop and implement an accidental release program consistent with requirements of the Clean Air Act, 40 CFR Part 68 (relating to chemical accident prevention provisions) and the Federal Chemical Safety Information, Site Security and Fuels Regulatory Relief Act (P.L. 106-40).

(b) The permittee shall prepare and implement a Risk Management Plan (RMP) which meets the requirements of Section 112(r) of the Clean Air Act, 40 CFR Part 68 and the Federal Chemical Safety Information, Site Security and Fuels Regulatory Relief Act when a regulated substance listed in 40 CFR § 68.130 is present in a process in more than the listed threshold quantity at the Title V facility. The permittee shall submit the RMP to the federal Environmental Protection Agency according to the following schedule and requirements:

(1) The permittee shall submit the first RMP to a central point specified by EPA no later than the latest of the following:

(i) Three years after the date on which a regulated substance is first listed under § 68.130; or,

(ii) The date on which a regulated substance is first present above a threshold quantity in a process.

(2) The permittee shall submit any additional relevant information requested by the Department or EPA concerning the RMP and shall make subsequent submissions of RMPs in accordance with 40 CFR § 68.190.

(3) The permittee shall certify that the RMP is accurate and complete in accordance with the requirements of 40 CFR Part 68, including a checklist addressing the required elements of a complete RMP.

(c) As used in this permit condition, the term "process" shall be as defined in 40 CFR § 68.3. The term "process" means any activity involving a regulated substance including any use, storage, manufacturing, handling, or on-site movement of such substances or any combination of these activities. For purposes of this definition, any group of vessels that are interconnected, or separate vessels that are located such that a regulated substance could be involved in a potential release, shall be considered a single process.

(d) If the Title V facility is subject to 40 CFR Part 68, as part of the certification required under this permit, the permittee shall:

(1) Submit a compliance schedule for satisfying the requirements of 40 CFR Part 68 by the date specified in 40 CFR § 68.10(a); or,

(2) Certify that the Title V facility is in compliance with all requirements of 40 CFR Part 68 including the registration and submission of the RMP.

(e) If the Title V facility is subject to 40 CFR Part 68, the permittee shall maintain records supporting the implementation of an accidental release program for five (5) years in accordance with 40 CFR § 68.200.

(f) When the Title V facility is subject to the accidental release program requirements of Section 112(r) of the Clean Air Act and 40 CFR Part 68, appropriate enforcement action will be taken by the Department if:

(1) The permittee fails to register and submit the RMP or a revised plan pursuant to 40 CFR Part 68.

(2) The permittee fails to submit a compliance schedule or include a statement in the compliance certification required under Condition #24 of Section B of this Title V permit that the Title V facility is in compliance with the requirements of Section 112(r) of the Clean Air Act, 40 CFR Part 68, and 25 Pa. Code § 127.512(i).

#027 [25 Pa. Code § 127.512(e)]
Approved Economic Incentives and Emission Trading Programs

No permit revision shall be required under approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this Title V permit.

#028 [25 Pa. Code §§ 127.516, 127.450(d), 127.449(f) & 127.462(g)]
Permit Shield

(a) The permittee's compliance with the conditions of this permit shall be deemed in compliance with applicable requirements (as defined in 25 Pa. Code § 121.1) as of the date of permit issuance if either of the following applies:

(1) The applicable requirements are included and are specifically identified in this permit.

(2) The Department specifically identifies in the permit other requirements that are not applicable to the permitted facility or source.

(b) Nothing in 25 Pa. Code § 127.516 or the Title V permit shall alter or affect the following:

(1) The provisions of Section 303 of the Clean Air Act, including the authority of the Administrator of the EPA provided thereunder.

(2) The liability of the permittee for a violation of an applicable requirement prior to the time of permit issuance.

(3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act.

(4) The ability of the EPA to obtain information from the permittee under Section 114 of the Clean Air Act.

(c) Unless precluded by the Clean Air Act or regulations thereunder, final action by the Department on minor or significant permit modifications, and operational flexibility changes shall be covered by the permit shield. Upon taking final action granting a request for an administrative permit amendment, the Department will allow coverage of the amendment by the permit shield in § 127.516 for administrative amendments which meet the relevant requirements of 25 Pa. Code Article III.

(d) The permit shield authorized under § 127.516 is in effect for the permit terms and conditions in this Title V permit, including administrative operating permit amendments and minor operating permit modifications.

SECTION C. Site Level Requirements

I. **RESTRICTIONS.**

Emission Restriction(s).

 # 001 [25 Pa. Code §123.1]
Prohibition of certain fugitive emissions
(a) No person may permit the emission into the outdoor atmosphere of fugitive air contaminants from a source other than the following:

(1) Construction or demolition of buildings or structures.

(2) Grading, paving and maintenance of roads and streets.

(3) Use of roads and streets. Emissions from material in or on trucks, railroad cars and other vehicular equipment are not considered as emissions from use of roads and streets.

(4) Clearing of land.

(5) Stockpiling of materials.

(6) Open burning operations.

(7) Not Applicable

(8) Not Applicable

(9) Sources and classes of sources other than those identified above, for which the permittee has obtained a determination from the Department that fugitive emissions from the source, after appropriate control, meet the following requirements:

(i) The emissions are of minor significance with respect to causing air pollution.

(ii) The emissions are not preventing or interfering with the attainment or maintenance of any ambient air quality standard.

 # 002 [25 Pa. Code §123.2]
Fugitive particulate matter
No person may permit fugitive particulate matter to be emitted into the outdoor atmosphere from a source specified in condition #001(a)(1) - (a)(9) above if the emissions are visible at the point the emissions pass outside the person's property.

 # 003 [25 Pa. Code §123.41]
Limitations
No person may permit the emission into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following:

(1) Equal to or greater than 20% for a period or periods aggregating more than three minutes in any 1 hour.

(2) Equal to or greater than 60% at any time.

 # 004 [25 Pa. Code §123.42]
Exceptions
The emission limitations of 25 Pa Code Section 123.41 shall not apply when:

(1) The presence of uncombined water is the only reason for failure of the emission to meet the limitations;

(2) The emission results from the operation of equipment used solely to train and test persons in observing the opacity of visible emissions;

(3) The emissions results from sources specified in 25 Pa Code Section 123.1(a)(1)-(9);

(4) Not Applicable

Fuel Restriction(s).

 # 005 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Sections 123.22]

The sulfur content of the #2 and lighter fuel oil delivered to this facility shall not exceed 0.5% (by weight).

II. TESTING REQUIREMENTS.

 # 006 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall perform tests (in accordance with the provisions of 25 Pa. Code Chapter 139) or provide a fuel certification report of the percent sulfur by weight of each delivery of the fuel oil delivered to this facility.

OR

The permittee shall keep records of the fuel certification reports obtained yearly from the fuel oil supplier stating that the sulfur percentage for each shipment of fuel oil delivered to the facility during the year shall not exceed 0.5% sulfur by weight.

 # 007 [25 Pa. Code §127.441]
Operating permit terms and conditions.
(a) Pursuant to 25 Pa. Code § 139.3, at least 45 calendar days prior to commencing a EPA reference method testing program, a test protocol shall be submitted to the Department for review and approval. The test protocol shall meet all applicable requirements specified in the most current version of the Department's Source Testing Manual.

(b) Pursuant to 25 Pa. Code § 139.3, at least 15 calendar days prior to commencing an emission testing program, notification as to the date and time of testing shall be given to the appropriate Regional Office. Notification shall also be sent to the Division of Source Testing and Monitoring. Notification shall not be made without prior receipt of a protocol acceptance letter from the Department.

(c) Pursuant to 25 Pa. Code Section 139.53(a)(3) within 15 calendar days after completion of the on-site testing portion of a EPA reference method test program, if a complete test report has not yet been submitted, an electronic mail notification shall be sent to the Department's Northcentral Regional Office and Division of Source Testing and Monitoring indicating the completion date of the on-site testing.

(d) Pursuant to 40 CFR Part 60.8(a), 40 CFR Part 61.13(f) and 40 CFR Part 63.7(g), complete test reports shall be submitted to the Department no later than 60 calendar days after completion of the on-site testing portion of a EPA reference method test program.

(e) Pursuant to 25 Pa. Code Section 139.53(b) a complete test report shall include a summary of the emission results on the first page of the report indicating if each pollutant measured is within permitted limits and a statement of compliance or non-compliance with all applicable permit conditions. The summary results will include, at a minimum, the following information:
1. A statement that the owner or operator has reviewed the report from the emissions testing body and agrees with the findings.
2. Permit number(s) and condition(s) which are the basis for the evaluation.
3. Summary of results with respect to each applicable permit condition.
4. Statement of compliance or non-compliance with each applicable permit condition.

(f) Pursuant to 25 Pa. Code § 139.3, all submittals shall meet all applicable requirements specified in the most current version of the Department's Source Testing Manual.

(g) All testing shall be performed in accordance with the provisions of Chapter 139 of the Rules and Regulations of theDepartment of Environmental Protection.

(h) Pursuant to 25 Pa. Code Section 139.53(a)(1) and 139.53(a)(3) all submittals, besides notifications, shall be accomplished through PSIMS*Online available through https://www.depgreenport.state.pa.us/ecomm/Login.jsp when it becomes available. If internet submittal can not be accomplished, two (2) copies of the submittal shall be sent to the Pennsylvania Department of Environmental Protection, Northcentral Regional Office, Air Quality Program Manager, 208 West Third Street, Suite 101, Williamsport PA, 17701 with deadlines verified through document postmarks.

(i) The permittee shall insure all federal reporting requirements contained in the applicable subpart of 40 CFR are followed, including timelines more stringent than those contained herein. In the event of an inconsistency or any conflicting requirements between state and the federal, the most stringent provision, term, condition, method or rule shall be used by default.

 # 008 [25 Pa. Code §139.1]
Sampling facilities.

Upon the request of the Department, the person responsible for a source shall provide adequate sampling ports, safe sampling platforms and adequate utilities for the performance by the Department of tests on such source. The Department will set forth, in the request, the time period in which the facilities shall be provided as well as the specifications for such facilities.

 # 009 [25 Pa. Code §139.11]
General requirements.

(a) As specified in 25 Pa. Code Section 139.11(1), performance tests shall be conducted while the source is operating at maximum routine operating conditions or under such other conditions, within the capacity of the equipment, as may be requested by the Department.

(b) As specified in 25 Pa. Code Section 139.11(2), the Department will consider test results for approval where sufficient information is provided to verify the source conditions existing at the time of the test and where adequate data is available to show the manner in which the test was conducted. Information submitted to the Department shall include, as a minimum all of the following:

(1) A thorough source description, including a description of any air cleaning devices and the flue.

(2) Process conditions, for example, the charging rate of raw materials or the rate of production of final product, boiler pressure, oven temperature and other conditions which may effect emissions from the process.

(3) The location of sampling ports.

(4) Effluent characteristics, including velocity, temperature, moisture content, gas density (percentage CO, CO2, O2 and N2), static and barometric pressures.

(5) Sample collection techniques employed, including procedures used, equipment descriptions and data to verify that isokinetic sampling for particulate matter collection occurred and that acceptable test conditions were met.

(6) Laboratory procedures and results.

(7) Calculated results.

III. MONITORING REQUIREMENTS.

 # 010 [25 Pa. Code §123.43]
Measuring techniques

Visible emissions may be measured using either of the following:

(1) A device approved by the Department and maintained to provide accurate opacity measurements.

(2) Observers, trained and certified, to measure plume opacity with the naked eye or with the aid of any devices approved by the Department.

SECTION C. Site Level Requirements

 # 011 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall conduct a weekly inspection of the facility during daylight hours while the facility is operating to detect visible emissions, visible fugitive emissions and malodors. Weekly inspections are necessary to determine:

(1) the presence of visible emissions.

(2) the presence of visible fugitive emissions.

(3) the presence of malodors beyond the boundaries of the facility.

(b) All detected visible emissions, visible fugitive emissions or malodors that have the potential to exceed applicable limits shall be reported to the manager of the facility.

IV. RECORDKEEPING REQUIREMENTS.

 # 012 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall maintain a logbook of the weekly facility inspections and shall record instances of visible emissions, visible fugitive emissions and malodorous air emissions, the name of the company representative monitoring these instances, and the date and time of each occurrence. The permittee shall also record the corrective action(s) taken to abate each recorded deviation or to prevent future occurrences.

(b) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 013 [25 Pa. Code §135.5]
Recordkeeping
The permittee shall maintain and make available upon request by the Department records including computerized records that may be necessary to comply with 135.3 and 135.21 (relating to reporting; and emissions statements). These may include records of production, fuel usage, maintenance of production or pollution control equipment or other information determined by the Department to be necessary for identification and quantification of potential and actual air contaminant emissions.

V. REPORTING REQUIREMENTS.

 # 014 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit conditions is also derived from 25 Pa. Code Section 127.511]

(a) The permittee shall submit the annual compliance certifications to the Department and EPA Region III, as specified in Condition #024 of Section B, General Title V Requirements, no later than September 1 (from July of the previous year through June of the current year).

(b) The permittee shall submit the semiannual reports of required monitoring to the Department, as specified in Condition #023 of Section B, General Title V Requirements, no later than September 1 (for January through June) and March 1 (for July through December of the previous year).

 # 015 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is also derived from 25 Pa. Code Section 127.442]

(a) The permittee shall report each malfunction that poses an imminent and substantial danger to the public health and safety or the environment or which it should reasonably believe may result in citizens compliants to the Department that occurs at this facility. For purposes of this condition a malfunction is defined as 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 that may result in an increase in the emissions of air contaminants.

(b) When the malfunction poses an imminent and substantial danger to the public health and safety, the notification shall be submitted to the Department no later than one hour after the incident.

(1) The notice shall describe the:

(i) name and location of the facility;
(ii) nature and cause of the malfunction;
(iii) time when the malfunction or breakdown was first observed;
(iv) expected duration of excess emissions; and
(v) estimated rate of emissions.

(2) The permittee shall notify the Department immediately when corrective measures have been accomplished.

(3) Subsequent to the malfunction, the owner or operator shall submit a full report on the malfunction to the Department within 15 days, if requested.

(4) The permittee shall submit reports on the operation and maintenance of the source to the Regional Air Program Manager at such intervals and in such form and detail as may be required by the Department. Information required in the reports may include, but is not limited to, process weight rates, firing rates, hours of operation, and maintenance schedules.

(c) Malfunctions shall be reported to the Department at the following address:

Air Program Manager
Pennsylvania Department of Environmental Protection
Air Quality Program
208 West Third Street, Suite 101
Williamsport, PA 17701-6448

 # 016 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Upon request by the Department, the permittee shall submit all requested reports in accordance with the Department's suggested format.

 # 017 [25 Pa. Code §135.21]
Emission statements

(a) The permittee shall provide the Department with a statement of each stationary source in a form as prescribed by the Department, showing the actual emissions of oxides of nitrogen and volatile organic compounds (VOCs) from the permitted facility for each reporting period, a description of the method used to calculate the emissions and the time period over which the calculation is based.

(b) The annual emission statements are due by March 1 for the preceding calendar year and shall contain a certification by a company officer or the plant manager that the information contained in the statement is accurate. The Emission Statement shall provide data consistent with requirements and guidance developed by the EPA.

(c) The Department may require more frequent submittals if the Department determines that one or more of the following applies:

(1) A more frequent submission is required by the EPA.

(2) Analysis of the data on a more frequent basis is necessary to implement the requirements of the Air Pollution Control Act.

 # 018 [25 Pa. Code §135.3]
Reporting

(a) A permittee to which 25 Pa. Code Chapter 135 applies, and who has previously been advised by the Department to submit an annual Air Information Management Systems (AIMS) report, shall submit by March 1 of each year an annual AIMS report for the preceding calendar year. The report shall include information for all previously reported sources, new sources which were first operated during the preceding calendar year and sources modified during the same period which were not previously reported.

(b) Not Applicable

(c) The permittee may request an extension of time from the Department for the filing of a source report, and the Department may grant the extension for reasonable cause.

VI. WORK PRACTICE REQUIREMENTS.

 # 019 [25 Pa. Code §123.1]
Prohibition of certain fugitive emissions

The permittee shall take all reasonable actions for any source specified in 25 Pa Code Section 123.1(a)(1-7) or (9) to prevent particulate matter from becoming airborne. These actions shall include, but not be limited to, the following:

(1) Use, where possible, of water or chemicals for control of dust in the demolition of buildings or structures, construction operations, the grading of roads or the clearing of land.

(2) Application of asphalt, oil, water or suitable chemicals on dirt roads, material stockpiles and other surfaces which may give rise to airborne dusts.

(3) Paving and maintenance of roadways.

(4) Prompt removal of earth or other material from paved streets onto which earth or other material has been transported by trucking or earth moving equipment, erosion by water, or other means.

VII. ADDITIONAL REQUIREMENTS.

 # 020 [25 Pa. Code §121.7]
Prohibition of air pollution.

No person may permit air pollution as that term is defined in the act (The Air Pollution Control Act (35 P.S. §§ 4001-4015)).

 # 021 [25 Pa. Code §123.31]
Limitations

No person may permit the emission into the outdoor atmosphere of any malodorous air contaminants from any source in a manner that the malodors are detectable outside the property of the person on whose land the source is being operated.

 # 022 [25 Pa. Code §127.441]
Operating permit terms and conditions.

In accordance with 40 CFR Part 97 (relating to Federal NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs), the permittee and the CAIR designated representative of the CAIR units at the Shawville Generating Station (CAIR source) are subject to 40 CFR § 97.106 (relating to standard requirements), 40 CFR § 97.206 (relating to standard requirements) and 40 CFR § 97.306 (relating to standard requirements).

 # 023 [25 Pa. Code §129.14]
Open burning operations

No person may permit the open burning of material at this facility unless in accordance with 25 Pa. Code Section 129.14.

VIII. COMPLIANCE CERTIFICATION.

No additional compliance certifications exist except as provided in other sections of this permit including Section B (relating to Title V General Requirements).

IX. COMPLIANCE SCHEDULE.

SECTION C. Site Level Requirements

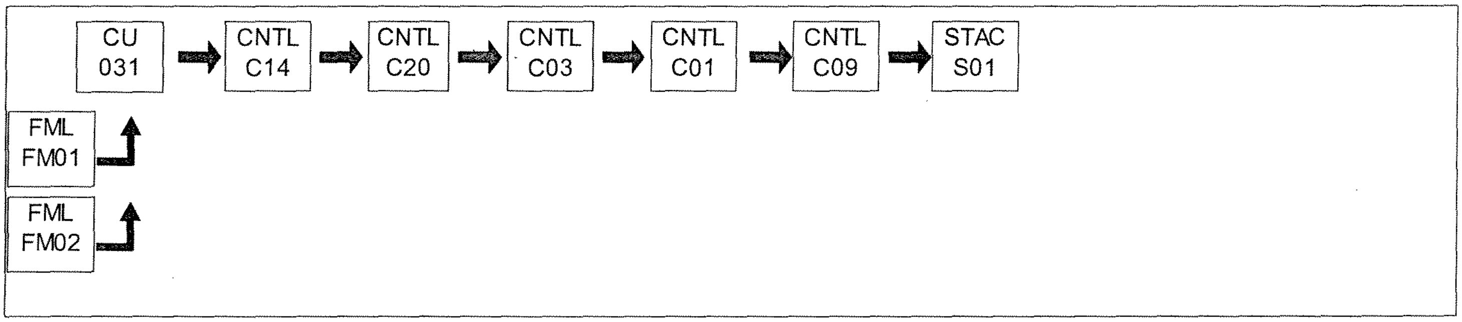
No compliance milestones exist.

*** Permit Shield In Effect ***

SECTION D. Source Level Requirements

Source ID: 031 Source Name: UTILITY BOILER - UNIT 1

Source Capacity/Throughput: 1,345.000 MMBTU/HR



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.11]
Combustion units
No person may permit the emission into the outdoor atmosphere of particulate matter from the exhaust of Source ID 031 in excess of 0.1 pound per million British thermal units (lb/MMBtu) of heat input.

 # 002 [25 Pa. Code §123.22]
Combustion units
(a) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 031 in excess of the rate of 4 lb/MMBtu of heat input over any 1-hour period when firing #2 fuel oil.

(b) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 031 in excess of the pounds of SO2 per million British thermal units heat input as shown below when firing solid fossil fuels:

Thirty-day running average not to be exceeded at any time: 3.7 lb/MMBtu

Daily average not to be exceeded more than 2 days in any running 30-day period: 4.0 lb/MMBtu

Daily average not to be exceeded at any time: 4.8 lb/MMBtu

 # 003 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 through 129.95]

The nitrogen oxides emissions (NOx, expressed as NO2) from the exhaust of Source ID 031 shall not exceed 0.524 lb/MMBtu of heat input based on a 30 day rolling average.

 # 004 [25 Pa. Code §127.441]
Operating permit terms and conditions.
The ammonia (NH3) emission rate from the exhaust of Source ID 031 shall not exceed 0.003 lb/MMBtu of heat input.

 # 005 [25 Pa. Code §127.441]
Operating permit terms and conditions.
The ammonia slip resulting from the operation of each SNCR systems (IDs C20, C21, C22 and C23) associated with Source IDs 031, 032, 033 and 034 shall not exceed 5 ppmv corrected to 8% oxygen.

 # 006 [25 Pa. Code §127.531]
Special conditions related to acid rain.
[Additional authority for this permit condition is also derived from 40 CFR Section 70.6(a)(4)]

(a) The permittee shall not emit into the outdoor atmosphere, annual emissions of sulfur dioxide in excess of the number of allowances to emit sulfur dioxide that the permittee or designated representative holds for each affected source.

(b) The permittee shall not emit sulfur dioxide in a manner that would exceed applicable emission rates or standards, including ambient air quality standards.

(c) The permittee shall not use a sulfur dioxide allowance prior to the year for which the allowance is allocated.

(d) A limit will not be placed on the number of sulfur dioxide allowances held for a source. The permittee shall not, however, use allowances as a defense to noncompliance with other applicable requirements.

(e) The permittee shall account for all allowances in accordance with the procedures established in regulations promulgated under Title IV of the Clean Air Act.

 # 007 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(c) Nitrogen oxides emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NOXsource and each CAIR NOXunit at the source shall hold, in the source's compliance account, CAIR NOXallowances available for compliance deductions for the control period under §97.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NOXunits at the source, as determined in accordance with subpart HH of this part.
(2) A CAIR NOXunit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on January 1, 2009.
(3) A CAIR NOXallowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NOXallowance was allocated.
(4) CAIR NOXallowances shall be held in, deducted from, or transferred into or among CAIR NOXAllowance Tracking System accounts in accordance with subparts EE, FF, GG, and II of this part.
(5) A CAIR NOXallowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NOXAnnual Trading Program. No provision of the CAIR NOXAnnual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §97.105 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(6) A CAIR NOXallowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart EE, FF, GG, or II of this part, every allocation, transfer, or deduction of a CAIR NOXallowance to or from a CAIR NOXsource's compliance account is incorporated automatically in any CAIR permit of the source.

 # 008 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(c) Sulfur dioxide emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO2source and each CAIR SO2unit at the source shall hold, in the source's compliance account, a tonnage equivalent in CAIR SO2allowances available for compliance deductions for the control period, as determined in accordance with §97.254(a) and (b), not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO2units at the source, as determined in accordance with subpart HHH of this part.
(2) A CAIR SO2unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2010 or the deadline for meeting the unit(s monitor certification requirements under §97.270(b)(1),(2), or (5) and for each control period thereafter.
(3) A CAIR SO2allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR SO2allowance was allocated.
(4) CAIR SO2allowances shall be held in, deducted from, or transferred into or among CAIR SO2Allowance Tracking System accounts in accordance with subparts FFF, GGG, and III of this part.
(5) A CAIR SO2allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO2Trading Program. No provision of the CAIR SO2Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §97.205 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(6) A CAIR SO2allowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart FFF, GGG, or III of this part, every allocation, transfer, or deduction of

a CAIR SO2allowance to or from a CAIR SO2source's compliance account is incorporated automatically in any CAIR permit of the source.

 # 009 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(c) Nitrogen oxides ozone season emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall hold, in the source's compliance account, CAIR NOXOzone Season allowances available for compliance deductions for the control period under §97.354(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NOXOzone Season units at the source, as determined in accordance with subpart HHHH of this part.

(2) A CAIR NOXOzone Season unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §97.370(b)(1), (2), (3), or (7) and for each control period thereafter.

(3) A CAIR NOXOzone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NOXOzone Season allowance was allocated.

(4) CAIR NOXOzone Season allowances shall be held in, deducted from, or transferred into or among CAIR NOXOzone Season Allowance Tracking System accounts in accordance with subparts EEEE, FFFF, GGGG, and IIII of this part.

(5) A CAIR NOXOzone Season allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NOXOzone Season Trading Program. No provision of the CAIR NOXOzone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §97.305 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(6) A CAIR NOXOzone Season allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart EEEE, FFFF, GGGG, or IIII of this part, every allocation, transfer, or deduction of a CAIR NOXOzone Season allowance to or from a CAIR NOXOzone Season source's compliance account is incorporated automatically in any CAIR permit of the source.

Fuel Restriction(s).

 # 010 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Section 123.22]

The sulfur content of the #2 and lighter fuel oil fired in Source ID 031 shall not exceed 0.5% (by weight).

 # 011 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from RFD condition approved April 8, 2002]

The only binding agents to be used in manufacturing the synthetic fuels used at the Shawville Station shall be soybean oil, Accretion Technologies FTH-100, Nalco 9838, Dow Covol 298 and Dow Covol 298-1 having the compositions identified in the materials submitted with the request for determination dated February 18, 2002 and approved on April 8, 2002. Additionally, the maximum application rate of the soybean oil shall be 1.0% by weight of the soybean oil/coal mixture and the maximum application rate of any of the other four binding agents shall be such that the maximum application rate of the combined non-water constituents contained in the binding agent shall never exceed 1.0% by weight of the binding agent/coal mixture.

II. TESTING REQUIREMENTS.

 # 012 [25 Pa. Code §127.441]
Operating permit terms and conditions.

All continuous emissions monitoring systems shall be tested in accordance with the applicable requirements specified in 25 Pa. Code Chapter 139, the Departments "Continuous Source Monitoring Manual" and 40 CFR Part 75.

 # 013 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable testing requirements specified in 25 Pa. Code Chapter 139 and the Departments "Source Testing Manual."

 # 014 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall conduct testing of the SNCR systems between January 1, 2014 and December 31, 2014 and every five years thereafter. The permittee shall conduct the following testing upon the exhaust of the utility boilers:

(a) Ammonia testing shall be conducted upon the exhausts of Source IDs 031 and 032, respectively, and the common exhaust of Source IDs 033 and 034 using EPA reference method stack testing or an alternative ammonia test method approved by the Department to determine ammonia slip levels and ammonia emissions from each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034.

(b) During the stack testing, the permittee shall measure and, record the gross megawatt load, NOx emissions and SNCR ammonia slip levels for each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034, and such information shall be provided in the stack test report submitted to the Department.

 # 015 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.6(b)(3)]

(a) Within 120 day of the issuance date of this permit, the permittee shall perform stack testing on the four utility boilers (Source IDs 031, 032, 033 and 034) to demonstrate compliance with the particulate matter emission limitation contained in this operating permit and obtain data to verify the validity of the Linear Regression equations and establish new Linear Regression equations (as approved by the Department) per the procedures in the 2007 CAM plan if the data warrants the establishment of new Linear Regression equations.

(b) Subsequent testing shall be performed on an approximate 2-year period, but in each case, no less than 20 months and no greater than 26 months following the date of the previous test.

(c) Stack testing shall be performed in accordance with the applicable provisions of 25 Pa. Code Chapter 139 (relating to sampling and testing) using test methods and procedures approved by the Department. Testing must be performed while the sources are operating under maximum normal operating conditions.

III. MONITORING REQUIREMENTS.

 # 016 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 123.25, 123.46, 123.51, 40 CFR Part 75]

The permittee shall install, calibrate, maintain and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxide emissions, carbon dioxide concentration (%CO2) and volumetric flow in accordance with all applicable requirements specified in, or established pursuant to: 25 Pa. Code Chapters 123 and 139, the Department's "Continuous Source Monitoring Manual" and 40 CFR Part 75.

 # 017 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable monitoring requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 018 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall install and maintain instrumentation to monitor and record the ammonia injection rate of the SNCR systems associated with Source IDs 031, 032, 033, and 034 on a continuous basis. Additionally, the permittee shall continuously monitor and record the gross megawatt load and NOx emissions associated with the boilers.

These records shall be retained for a minimum of five years and shall be presented to the Department upon request.

 # 019 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Authority for this condition is also derived from 40 CFR Part 64, relating to Compliance Assurance Monitoring (CAM)]

Compliance Assurance Monitoring (CAM) Protocol
(A) The purpose of this protocol is to outline procedures for the development, verification, operation, and ongoing maintenance of a continuous monitoring approach sufficient to reasonably assure that Source IDs 031, 032, 033, and 034 operate in compliance with the 0.1 lb/MMBtu particulate matter emission limitation.

(B) Monitoring designed and operated in accordance with this protocol satisfies the requirements of the CAM rule's monitoring design criteria in 40 CFR Section 64.3(a) and (b) pursuant to 40 CFR Section 64.3(d)(2).

I. CAM Indicators - Predicted Particulate Matter (PM) and Opacity of Exhaust
Measurement Approach - Predicted PM, in units of lb/MMBtu, using the % opacity measured by the COMS; the %CO2(w) measured by the CO2 CEMS; Unit's 3 and 4 gross megawatt load (MW) measured by the continuous gross megawatt load meter, data acquisition and handling system and Linear Regression equations (as approved by the Department).

II. CAM Indicator Parameters and Excursion
(A) As identified below, the predicted PM (1-hour average) is used as the CAM indicator paramater to comply with the requirements specified in 40 CFR Section 64.3(d)(3)(ii).

(B) The permittee shall assure the measured % opacity, %CO2(w), gross megawatt load and predicted PM are recorded in accordance to the requirements specified in 40 CFR Section 64.3(b)(4)(ii)

(C) The predicted PM for Units 1 and 2 shall be determined from the CAM indicators, including the predicted PM concentration, using the following equation:

lb/MMBtu = Y * (1 / 7000) * Fc * (100 / %CO2(w)) where,

Y = the predicted PM concentration (gr/scf) calculated by using the most recently approved Linear Regression equations
Fc = carbon-based F-factor
%CO2(w) = the %CO2 measured in accordance with item (d)(2) of this condiiton

(D) The predicted PM for Units 3 and 4 shall be determined from the CAM indicators, including the predicted PM concentration and emission apportionment factor (EAF) using the following equation:

lb/MMBtu = Y * (1 / 7000) * Fc * (100 / %CO2(w)) * EAF where,

Y = the predicted PM concentration (gr/scf) calculated by using the most recently approved Linear Regression equations,
Fc = carbon-based F-factor,
%CO2(w) = the %CO2 measured in accordance with item (d)(2) of this condiiton
EAF = each unit's average hourly gross megawatt load measured in accordance with item (d)(3) of this condition divided by the sum of hourly gross megawatt loads for Units 3 and 4.

(E) Each instance where the predicted PM rate (1-hour block average) exceeds 0.09 lb/MMBtu is defined to be an excursion.

(F) When an excursion occurs (the predicted PM rate, 1-hour block average exceeds 0.09 lb/MMBtu), the permittee shall initiate and comply with the requirements of 40 CFR Section 64.7(d).

III. Performance Criteria
(a) Data Representativeness
(1) The predicted PM using the % opacity measured by the COMS is proportional to the amount of filterable PM in the exhaust. Opacity shall be correlated to the PM concentration in accordance with the Investigative Program. The Investigative Program shall use the procedures specified in the 2007 CAM plan and the data obtained from the most recently approved stack tests for PM.

(b) Verification of Operational Status
(1) The operation of the COMS shall be verified by the presence of a valid opacity signal on the COMS readout; the results of the performance evaluations conducted as per 25 Pa. Code Chapter 139; and the presence of a valid result of the predicted PM rate (1-hour block average).

(c) QA/QC Practices
(1) The operation of the COMS and CEMS shall meet the requirements of 25 Pa. Code Chapter 139.

(2) See the condition under II. Testing Requirements for additional QA/QC practice requirements.

(d) Data Collection Procedures & Averaging Periods
(1) An electronic data handling and acquisition system (DAHS) shall collect data points representative of the opacity in the exhaust from the COMS approximately every 10 seconds. These % opacity readings shall be reduced to 1-minute averages and then to 1-hour averages.

(2) An electronic DAHS shall collect data points from the CO2 CEMS approximately every second. These %CO2(w) readings shall be reduced to 1-minute averages and then to 1-hour averages. Monitor response time shall be less than 15 minutes.

(3) An electronic DAHS shall collect data points from the continuous gross megawatt load meter installed on Unit 3 and 4 approximately every 15 minutes. The hourly average gross megawatt load meter for Unit 3 and 4 shall be calculated from the 15-minute data. Monitor response time shall be less than 15 minutes.

(4) An electronic DAHS shall calculate a minimum of 4 equally-spaced PM emission concentrations over a 1-hour period pursuant to the requirements of 40 CFR §64.3(b)(4)(ii). These PM emission concentrations will be calculated using the following equations. The following Linear Regression equations were obtained from the June 2005 testing program.

Y = (6.79E-05) * X^(2) for Unit 1

Y = (1.26E-05) * X^(2.5) for Unit 2

Y = (1.14E-05) * X^(2.3) for Unit 3 and 4 Common Stack,

Where Y = PM concentration (gr/scf)
X = Opacity (%)

(5) An electronic DAHS shall calculate a minimum of 4 equally-spaced PM rates, in units of lb/MMBtu over a 1-hour period pursuant to the requirements of 40 CFR §64.3(b)(4)(ii). These PM rates shall be calculated using the equations listed in this condition under II. (C) for Units 1 and 2 and II. (D) for Units 3 and 4. The 4 equally-spaced PM rates shall be reduced to 1-hour averages.

 # 020 [25 Pa. Code §145.213.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.170--96.175.

(a) The owner or operator of the CAIR NOx unit shall install, calibrate, maintain and operate a wattmeter, measure gross electrical output in megawatt-hours on a continuous basis and record the output of the wattmeter. If a generator is served by two or more units, the information to determine the heat input of each unit for that control period shall also be recorded, so as to allow each unit's share of the gross electrical output to be determined. If heat input data are used, the owner or

operator shall comply with the applicable provisions of 40 CFR Part 75 (relating to continuous emission monitoring).
(b) Not Applicable

 # 021 [25 Pa. Code §145.223.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.370--96.375.

(a) The owner or operator of the CAIR NOx Ozone Season unit shall install, calibrate, maintain and operate a wattmeter, measure gross electrical output in megawatt-hours on a continuous basis and record the output of the wattmeter. If a generator is served by two or more units, the information to determine the heat input of each unit for that control period shall also be recorded, so as to allow each unit's share of the gross electrical output to be determined. If heat input data are used, the owner or operator shall comply with the applicable provisions of 40 CFR Part 75 (relating to continuous emission monitoring).
(b) Not Applicable

 # 022 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.10]
Subpart B--Monitoring Provisions
General operating requirements.

The requirements in 40 CFR Section 75.10 apply.

 # 023 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.11]
Subpart B--Monitoring Provisions
Specific provisions for monitoring SO2 emissions (SO2 and flow monitors).

The requirements in 40 CFR 75.11 apply.

 # 024 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.12]
Subpart B--Monitoring Provisions
Specific provisions for monitoring NOx emissions (NOx and diluent gas monitors).

The requirements in 40 CFR 75.12(a) and (b) apply.

 # 025 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.13]
Subpart B--Monitoring Provisions
Specific provisions for monitoring CO2 emissions.

The requirements in 40 CFR 75.13(a) apply.

 # 026 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.14]
Subpart B--Monitoring Provisions
Specific provisions for monitoring opacity.

The requirements in 40 CFR 75.14(a) and (b) apply.

 # 027 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.2]
Subpart A--General
Applicability.

The requirements in 40 CFR 75.2 apply.

 # 028 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.20]
Subpart C--Operation and Maintenance Requirements
Certification and recertification procedures.

The requirements of 40 CFR 75.20 apply except for 40 CFR 75.20(e), (f) and (g).

 # 029 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.21]
Subpart C--Operation and Maintenance Requirements
Quality assurance and quality control requirements.

The requirements in 40 CFR 75.21(a)(1), (a)(2) and (a)(3) apply.

 # 030 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.22]
Subpart C--Operation and Maintenance Requirements
Reference test methods.

The requirements in 40 CFR 75.22 apply.

 # 031 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.24]
Subpart C--Operation and Maintenance Requirements
Out-of-control periods.

The requirements in 40 CFR 75.24 apply.

 # 032 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.30]
Subpart D--Missing Data Substitution Procedures
General provisions.

The requirements in 40 CFR 75.30 apply.

 # 033 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.4]
Subpart A--General
Compliance dates.

The requirements in 40 CFR 75.4(a)(3) apply.

 # 034 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.53]
Subpart F--Recordkeeping Requirements
Monitoring plan.

The requirements in 40 CFR 75.53 apply.

 # 035 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.60]
Subpart G--Reporting Requirements
General provisions.

The requirements in 40 CFR 75.60 apply.

 # 036 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.62]
Subpart G--Reporting Requirements
Monitoring plan.

The requirements of 40 CFR 75.62 apply.

 # 037 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.63]
Subpart G--Reporting Requirements
Initial certification or recertification application.

The requirements in 40 CFR 75.63 apply.

 # 038 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.64]
Subpart G--Reporting Requirements
Quarterly reports.

The requirements in 40 CFR 75.64 apply.

 # 039 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.65]
Subpart G--Reporting Requirements
Opacity reports.

The requirements in 40 CFR 75.65 apply.

 # 040 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR NOXsource and each CAIR NOXunit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HH of this part.
(2) The emissions measurements recorded and reported in accordance with subpart HH of this part shall be used to determine compliance by each CAIR NOXsource with the CAIR NOXemissions limitation under paragraph (c) of this section.

 # 041 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR SO2source and each CAIR SO2unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHH of this part.
(2) The emissions measurements recorded and reported in accordance with subpart HHH of this part shall be used to determine compliance by each CAIR SO2source with the CAIR SO2emissions limitation under paragraph (c) of this section.

 # 042 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of this part.
(2) The emissions measurements recorded and reported in accordance with subpart HHHH of this part shall be used to determine compliance by each CAIR NOXOzone Season source with the CAIR NOXOzone Season emissions limitation under paragraph (c) of this section.

IV. RECORDKEEPING REQUIREMENTS.

 # 043 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable recordkeeping requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 044 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall keep records of the data and calculations used to verify compliance with the particulate matter, sulfur oxides (SOx) and ammonia (NH3) emissions limitations for Source ID 031.

(b) The permittee shall keep records of the tests conducted or certification reports used to verify the sulfur content (percent by weight) of the fuel oil.

These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

 # 045 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

(a) The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95.

(b) The permittee shall keep records, including data which clearly demonstrates that the NOX emission limits for Source ID 031 are met.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

 # 046 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall keep records of the calculations, including ammonia emissions test reports, used to determine compliance with the SNCR ammonia slip emissions limitations for Source IDs 031, 032, 033 and 034. These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

 # 047 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall record all excursions and corrective actions taken in response to an excursion and the time elapsed until the corrective actions have been taken.

(b) The permittee shall keep records of all monitoring downtime incidents associated with the COMS and CO2 CEMS associated with Source IDs 031 through 034. The permittee shall also record the dates, times and durations, possible causes, and corrective actions taken for the incidents.

(c) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 048 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Compliance with the requirements in item (b) of this condition will assure compliance with the requirements of 40 CFR Section 64.7(c)]

[Additional authority items (a)-(b) of this condition is also derived from 40 CFR §64.6 & §64.3]

[Additional authority for permit conditions (c) is also derived from 40 CFR §64.9]

[Additional authority for permit condition (f) is also derived from 40 CFR §70.6(a)(3)(ii)(b)]

(a) The permittee shall use the following devices to monitor and record CAM indicators:
(i) The certified COMS that measure % opacity readings at a location downstream of each of the electrostatic precipitators (IDs C01, C04, C08, C09, C11, C12, C18, and C19).
(ii) The certified CEMS that measure the %CO2(w) at each of the stacks (ID S01 and S02)
(iii) Gross load meter to measure Unit's 3 and 4 gross megawatt load
(iv) Data Acquistion and handling systems (DAHS) to record all CAM indicators and calculate the predicted hourly PM rate, in units of lb/MMBtu.

(b) The permittee shall use the devices above to conduct monitoring and record the CAM indicators in accordance with the requirements of 40 CFR 64.3(b)(4)(ii).

(c) The permittee shall maintain supporting documentation to verify compliance with the requirements of 40 CFR Sections 64.9(a)(2)(i) and 64.7(b).

(d) The permittee shall maintain records of the operation of the devices above in order to report the information required in in 40 CFR Section 64.9(a)(2)(ii).

(e) The permittee shall maintain supporting information that verify that each response to an excursion meets the requirements of 40 CFR Section 64.7(d)

(f) The permittee shall keep all records for a period of five (5) years and shall make the records available to the Department upon request.

 # 049 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall keep records of all inspections, repairs, and maintenance performed on the devices used for Source IDs 031 through 034 CAM monitoring.

(b) The permittee shall record all excursions and corrective actions taken in response to an excursion and the time elapsed until the corrective actions have been taken.

(c) The permittee shall keep records of all monitoring downtime incidents associated with the devices used for Source IDs 031 through 034 CAM monitoring. The permittee shall also record the dates, times and durations, possible causes, and corrective actions taken for the downtime incidents.

(d) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 050 [25 Pa. Code §145.213.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.170--96.175.

(d) The owner or operator of a CAIR NOx unit shall maintain onsite the monitoring plan detailing the monitoring system and maintenance of the monitoring system, including quality assurance activities. The owner or operator of a CAIR NOx unit shall retain the monitoring plan for at least 5 years from the date that it is replaced by a new or revised monitoring plan. The owner or operator of a CAIR NOx Ozone Season unit shall provide the Department with a written copy of updates to the submitted monitoring plan, including a copy of the revised monitoring plan within 3 calendar months of making updates to the plan.
(e) The owner or operator of a CAIR NOx unit shall retain records for at least 5 years from the date the record is created or the data collected as required by subsections (a) and (b), and the reports submitted to the Department and the EPA in accordance with subsections (c) and (d).

 # 051 [25 Pa. Code §145.223.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.370--96.375.

(d) The owner or operator of a CAIR NOx Ozone Season unit shall maintain onsite the monitoring plan detailing the monitoring system and maintenance of the monitoring system, including quality assurance activities. The owner or operator of a CAIR NOx Ozone Season unit shall retain the monitoring plan for at least 5 years from the date that it is replaced by a new or revised monitoring plan. The owner or operator of a CAIR NOx Ozone Season unit shall provide the Department with a written copy of updates to the submitted monitoring plan, including a copy of the revised monitoring plan within 3 calendar months of making updates to the plan.
(e) The owner or operator of a CAIR NOx Ozone Season unit shall retain records for at least 5 years from the date the record is created or the data collected as required by subsections (a) and (b), and the reports submitted to the Department and the EPA in accordance with subsections (c) and (d).

 # 052 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR NOXsource and each CAIR NOXunit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §97.113 for the CAIR designated representative for the source and each CAIR NOXunit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.113 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subpart HH of this part, provided that to the extent that subpart HH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the

CAIR NOXAnnual Trading Program.
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NOXAnnual Trading Program or to demonstrate compliance with the requirements of the CAIR NOXAnnual Trading Program.

 # 053 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR SO2source and each CAIR SO2unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §97.213 for the CAIR designated representative for the source and each CAIR SO2unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.213 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subpart HHH of this part, provided that to the extent that subpart HHH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR SO2Trading Program.
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR SO2Trading Program or to demonstrate compliance with the requirements of the CAIR SO2Trading Program.

 # 054 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §97.313 for the CAIR designated representative for the source and each CAIR NOXOzone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.313 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subpart HHHH of this part, provided that to the extent that subpart HHHH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NOXOzone Season Trading Program.
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NOXOzone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NOXOzone Season Trading Program.

V. REPORTING REQUIREMENTS.

 # 055 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable reporting requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 056 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9 and Section 70.6(a)(3)(iii)(A)]

(a) The permittee shall submit reports to the Department on a semi-annual basis that include the records of all excursions and corrective actions taken, the dates, times, durations, and possible causes.

(b) The permittee shall submit reports to the Department on a semi-annual basis that include all monitoring downtime incidents, their dates, times and durations, possible causes, and corrective actions taken.

(c) The semi-annual reports shall be submitted to the Department no later than March 1 (for July 1 through December 31 of the previous year) and September 1 (for January 1 through June 30 of the current year).

 # 057 [25 Pa. Code §145.213.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.170--96.175.

(c) The designated representative of the units associated with Source IDs 031 through 034 shall submit to the Department an annual report showing monthly gross electrical output and monthly useful thermal energy from the unit. The report is due by January 31 for the preceding calendar year.

 # 058 [25 Pa. Code §145.223.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.370--96.375.

(c) The designated representative of the units associated with Source IDs 031 through 034 shall submit to the Department an annual report showing monthly gross electrical output and monthly useful thermal energy from the unit. The report is due by January 31 for the preceding calendar year.

 # 059 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(b)(2) The CAIR designated representative of a CAIR NOXsource and each CAIR NOXunit at the source shall submit the reports required under the CAIR NOXAnnual Trading Program, including those under subpart HH of this part.

 # 060 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(e)(2) The CAIR designated representative of a CAIR SO2source and each CAIR SO2unit at the source shall submit the reports required under the CAIR SO2Trading Program, including those under subpart HHH of this part.

 # 061 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(e)(2) The CAIR designated representative of a CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall submit the reports required under the CAIR NOXOzone Season Trading Program, including those under subpart HHHH of this part.

VI. WORK PRACTICE REQUIREMENTS.

 # 062 [25 Pa. Code §127.441]
Operating permit terms and conditions.

No reclaimed or waste oil or oil that contains any waste material shall be used as fuel in the lighter associated with the low NOX burners of Source ID 031.

 # 063 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 129.91]

The permittee shall maintain and operate Source ID 031 in accordance with the manufacturers specifications. This requirement shall be considered as VOC RACT for Source ID 031.

 # 064 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The SNCR systems (Control Device IDs C20, C21, C22, and C23) shall be operated in accordance with the manufacturer specifications and good air pollution control practices.

 # 065 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall comply with the requirements specified in 40 CFR Section 64.7(b) and (d), relating to Proper maintenance and Response to excursions, respectively.

VII. ADDITIONAL REQUIREMENTS.

 # 066 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source ID 031 is a 1954 vintage, Babcock Wilcox, dry bottom, front wall-fired, balanced draft, divided furnace drum type utility boiler with a rated heat input of 1,345 MMBtu/hr. The boiler is fueled with pulverized bituminous coal/synfuel or #2 oil. The air contaminant emissions from the subject boiler shall be controlled by 16 Dual Register Low NOX (DRB-XCL) Babcock and Wilcox burners (Control Device ID C14), a NH3/SO3 injection flue gas conditioning system (Control Device ID C03) and a two stage Research Cottrell & Buell electrostatic precipitator (Control Device IDs C01 and C09).

The nitrogen oxides emissions from Source ID 031 may further be controlled by an Energy System Associates selective non-catalytic reduction system (Control Device ID C20).

 # 067 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Control Device IDs C20 and C21 associated with Source IDs 031 and 032 are considered SNCR system #1, which also consists of a storage tank and a recirculation pump. Control Device IDs C22 and C23 associated with Source IDs 033 & 034 are considered SNCR system #2, which also consists of a storage tank and a recirculation pump.

 # 068 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.8]

(a) The permittee shall develop and implement a Quality Improvement Plan (QIP) as expeditiously as practicable if any of the following occur:
(1) Six (6) excursions occur in a six (6) month reporting period.
(2) The Department determines after review of all reported information that the permittee has not responded acceptably to an excursion.

(b) The QIP should be developed within 60 days and the permittee shall provide a copy of the QIP to the Department. Furthermore, the permittee shall notify the Department if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(c) The permittee shall record actions taken to implement a QIP during a reporting period and all related actions including, but not limited to, inspections, repairs, and maintenance performed on the COMS, CO2 CEMS, gross megawatt load meter and DAHS.

(d) In accordance with 40 CFR Section 64.8, the QIP shall include procedures for evaluating the control performance problems. Based on the results of the evaluation procedures, the permittee shall modify the QIP and provide the Department with a copy, to include procedures for conducting more frequent, or improved, monitoring in conjunction with one or more of the following:
(1) Improved preventive maintenance practices,
(2) Process operation changes,

(3) Appropriate improvements to the control methods,
(4) Other steps appropriate to correct performance.

(e) Following implementation of a QIP, the Department will require reasonable revisions to the QIP if the plan has failed to either:
(1) Address the cause of the performance problems of the COMS, CO2 CEMS, gross megawatt load meter and/or DAHS.
(2) Provide adequate procedures for correcting the performance problems of the device(s) in an expeditious manner and according to good air pollution control practices.

(f) Implementation of a QIP shall not excuse the permittee from compliance with any existing emission limitation or standard or any existing monitoring, testing, reporting or recordkeeping requirements that may apply under any federal, state, or local laws or any other applicable requirements under the Clean Air Act.

 # 069 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source IDs 031 through 034 are subject to the CAM requirements of 40 CFR Part 64. The permittee shall comply with all applicable requirements of 40 CFR Sections 64.1 through 64.10.

 # 070 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source IDs 031 through 034 are defined to be affected sources in the National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (77 FR 9304). As the owner and operator of Source IDs 031 and 034, the permittee shall comply with all applicable requirements codified in 40 CFR Part 63 Subpart UUUUU (40 CFR §§ 63.9980 through 63.10042, including Tables and Appendices).

 # 071 [25 Pa. Code §127.531]
Special conditions related to acid rain.

The permittee shall comply with all applicable requirements and procedures established in regulations promulgated under Title IV of the Clean Air Act, including all applicable provisions from the following:

40 CFR Part 72	Permit Regulation
40 CFR Part 73	Sulfur Dioxide Allowance System
40 CFR Part 75	Continuous Emission Monitoring
40 CFR Part 76	Nitrogen Oxides Emission Reduction Program
40 CFR Part 77	Excess Emissions

Attached to Title V Operating Permit 17-00001 is the Phase II Title IV Operating Permit 17-00001 (Acid Rain Permit) in its entirety. The Acid Rain Permit was renewed on May 29, 2009 and is effective through December 31, 2012. Certain requirements from the Acid Rain permit have been reiterated in the body of the Title V operating permit for emphasis. The entire Acid Rain Permit is incorporated into the Title V operating permit by inclusion.

 # 072 [25 Pa. Code §145.204.]
Incorporation of Federal regulations by reference.

(a) Except as otherwise specified in this subchapter and herein, the provisions of the CAIR NOx Annual Trading Program, found in 40 CFR Part 96 (relating to NOx budget trading program and CAIR NOx and SO2 trading programs for State implementation plans), including all appendices, future amendments and supplements thereto, are incorporated by reference.
(b) Except as otherwise specified in this subchapter and herein, the provisions of the CAIR SO2 Trading Program, found in 40 CFR Part 96, including all appendices, future amendments and supplements thereto, are incorporated by reference.
(c) Except as otherwise specified in this subchapter and herein, the provisions of the CAIR NOx Ozone Season Trading Program, found in 40 CFR Part 96, including all appendices, future amendments and supplements thereto, are incorporated by reference.
(d) In the event of a conflict between Federal regulatory provisions incorporated by reference in this subchapter and Pennsylvania regulatory provisions, the provision expressly set out in this subchapter shall be followed unless the Federal provision is more stringent. Federal regulations that are cited in this subchapter or that are cross-referenced in the Federal regulations incorporated by reference include any Pennsylvania modifications made to those Federal regulations.

 # 073 [25 Pa. Code §145.205.]
Emission reduction credit provisions.

The following conditions shall be satisfied in order for the Department to issue a permit or plan approval to the owner or operator of a unit not subject to this subchapter that is relying on emission reduction credits (ERCs) or creditable emission reductions in an applicability determination under Chapter 127, Subchapter E (relating to new source review), or is seeking to enter into an emissions trade authorized under Chapter 127 (relating to construction, modification, reactivation and operation of sources), if the ERCs or creditable emission reductions were, or will be, generated by a unit subject to this subchapter.

(1) Prior to issuing the permit or plan approval, the Department will permanently reduce the Commonwealth's CAIR NOx trading budget or CAIR NOx Ozone Season trading budget, or both, as applicable, beginning with the sixth control period following the date the plan approval or permit to commence operations or increase emissions is issued. The Department will permanently reduce the applicable CAIR NOx budgets by an amount of allowances equal to the ERCs or creditable emission reductions relied upon in the applicability determination for the non-CAIR unit subject to Chapter 127, Subchapter E or in the amount equal to the emissions trade authorized under Chapter 127, as if these emissions had already been emitted.

(2) The permit or plan approval must prohibit the owner or operator from commencing operation or increasing emissions until the owner or operator of the CAIR unit generating the ERC or creditable emission reduction surrenders to the Department an amount of allowances equal to the ERCs or emission reduction credits relied upon in the applicability determination for the non-CAIR unit under Chapter 127, Subchapter E or the amount equal to the ERC trade authorized under Chapter 127, for each of the five consecutive control periods following the date the non-CAIR unit commences operation or increases emissions. The allowances surrendered must be of present or past vintage years.

 # 074 [25 Pa. Code §145.212.]
CAIR NOx allowance allocations.

(a) Provisions not incorporated by reference. The requirements of 40 CFR 96.142 (relating to CAIR NOx allowance allocations) are not incorporated by reference. Instead of 40 CFR 96.142, the requirements set forth in this section apply.

(b) Baseline heat input. Baseline heat input for each CAIR NOx unit will be converted as follows:

(1) A unit's control period heat input and a unit's status as coal-fired or oil-fired for a calendar year under this paragraph will be determined in one of the following two ways:

(i) In accordance with 40 CFR Part 75 (relating to continuous emission monitoring), to the extent that the unit was otherwise subject to 40 CFR Part 75 for the year.

(ii) Based on the best available data reported to the Department for the unit, to the extent the unit was not otherwise subject to the requirements of 40 CFR Part 75 for the year.

(2) Except as provided in subparagraphs (iv) and (v), a unit's converted control period heat input for a calendar year shall be determined as follows:

(i) The control period gross electrical output of the generators served by the unit multiplied by 7,900 Btu/kWh if the unit is coal-fired for the year, and divided by 1,000,000 Btu/mmBtu.

(ii) The control period gross electrical output of the generators served by the unit multiplied by 6,675 Btu/kWh if the unit is not coal-fired for the year, and divided by 1,000,000 Btu/mmBtu.

(iii) Not Applicable

(iv) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating or cooling purposes through the sequential use of energy, the total heat energy (in Btus) of the steam produced by the boiler during the annual control period, divided by 0.8 and by 1,000,000 Btu/mmBtu.

(v) Not Applicable

(vi) Calculations will be based on the best output data available on or before January 31 of the year the allocations are published. If unit level electrical or steam output data are not available from EIA, or submitted by this date by the owner or operator of the CAIR NOx unit, then heat input data for the period multiplied by 0.25 and converted to MWh will be used to determine total output.

(c) Existing unit, new unit and subsection (f)(1) qualifying resource allocation baseline. For each control period beginning with January 1, 2010, and each year thereafter, the Department will allocate to qualifying resources and CAIR NOx units, including CAIR NOx units issued allowances under subsection (e), a total amount of CAIR NOx allowances equal to the number of CAIR NOx allowances remaining in the Commonwealth's CAIR NOx trading budget under 40 CFR 96.140 (relating to State trading budgets) for those control periods using summed baseline heat input data as determined under subsections (b) and (f)(1) from a baseline year that is 6 calendar years before the control period.

(d) Proration of allowance allocations. The Department will allocate CAIR NOx allowances to each existing CAIR NOx unit and qualifying resource in an amount determined by multiplying the amount of CAIR NOx allowances in the Commonwealth's CAIR NOx trading budget available for allocation under subsection (c) by the ratio of the baseline heat input of the existing CAIR NOx unit or qualifying resource to the sum of the baseline heat input of existing CAIR NOx units and of the qualifying resources, rounding to the nearest whole allowance as appropriate.

(e) Allocations to new CAIR NOx units. By March 31, 2011, and March 31 each year thereafter, the Department will allocate CAIR NOx allowances under § 145.211(c) (relating to timing requirements for CAIR NOx allowance allocations) to CAIR NOx units equal to the previous year's emissions at each unit, unless the unit has been issued allowances of the previous year's vintage in a regular allocation under § 145.211(b). The Department will allocate CAIR NOx allowances under this subsection of a vintage year that is 5 years later than the year in which the emissions were generated. The number of CAIR NOx allowances allocated may not exceed the actual emission of the year preceding the year in which the Department makes the allocation. The allocation of these allowances to the new unit will not reduce the number of allowances the unit is entitled to receive under another provision of this subchapter.

(f) Allocations to qualifying resources and units exempted by section 405(g)(6)(a) of the Clean Air Act. For each control period beginning with 2010 and thereafter, the Department will allocate CAIR NOx allowances to qualifying resources under paragraph (1) in this Commonwealth that are not also allocated CAIR NOx allowances under another provision of this subchapter and to existing units under paragraph (2) that were exempted at any time under section 405(g)(6)(a) of the Clean Air Act (42 U.S.C.A. § 7651d(g)(6)(A)), regarding phase II SO2 requirements, and that commenced operation prior to January 1, 2000, but did not receive an allocation of SO2 allowances under the EPA's Acid Rain Program, as follows:

(1) The Department will allocate CAIR NOx allowances to a renewable energy qualifying resource or demand side management energy efficiency qualifying resource in accordance with subsections (c) and (d) upon receipt by the Department of an application, in writing, on or before June 30 of the year following the control period, except for vintage year 2011 and 2012 NOx allowance allocations whose application deadline will be prescribed by the Department, meeting the requirements of this paragraph. The number of allowances allocated to the qualifying resource will be determined by converting the certified quantity of electric energy production, useful thermal energy, and energy equivalent value of the measures approved under the Pennsylvania Alternative Energy Portfolio Standard to equivalent thermal energy. Equivalent thermal energy is a unit's baseline heat input for allocation purposes. The conversion rate for converting electrical energy to equivalent thermal energy is 3,413 Btu/kWh. To receive allowances under this subsection, the qualifying resource must have commenced operation after January 1, 2005, must be located in this Commonwealth and may not be a CAIR NOx unit. The following procedures apply:

(i) The owner of a qualifying renewable energy resource shall appoint a CAIR-authorized account representative and file a certificate of representation with the EPA and the Department.

(ii) The Department will transfer the allowances into an account designated by the owner's CAIR-authorized account representative of the qualifying resource, or into an account designated by an aggregator approved by the Pennsylvania Public Utility Commission or its designee.

(iii) The applicant shall provide the Department with the corresponding renewable energy certificate serial numbers.

(iv) At least one whole allowance must be generated per owner, operator or aggregator for an allowance to be issued.

(2) The Department will allocate CAIR NOx allowances to the owner or operator of a CAIR SO2 unit that commenced operation prior to January 1, 2000, that has not received an SO2 allocation for that compliance period, as follows:

(i) By January 31, 2011, and each year thereafter, the owner or operator of a unit may apply, in writing, to the Department under this subsection to receive extra CAIR NOx allowances.

(ii) The owner or operator may request under this subparagraph one CAIR NOx allowance for every 8 tons of SO2 emitted from a qualifying unit during the preceding control period. An owner or operator of a unit covered under this subparagraph that has opted into the Acid Rain Program may request one CAIR NOx allowance for every 8 tons of SO2 emissions that have not been covered by the SO2 allowances received as a result of opting into the Acid Rain Program.

(iii) If the original CAIR NOx allowance allocation for the unit for the control period exceeded the unit¿s actual emissions of NOx for the control period, the owner or operator shall also deduct the excess CAIR NOx allowances from the unit's request under subparagraph (ii). This amount is the unit's adjusted allocation and will be allocated unless the proration described in subparagraph (iv) applies.

(iv) The Department will make any necessary corrections and then sum the requests. If the total number of NOx allowances requested by all qualified units under this paragraph, as adjusted by subparagraph (iii), is less than 1.3% of the Commonwealth's CAIR NOx Trading Budget, the Department will allocate the corrected amounts. If the total number of NOx allowances requested by all qualified units under this paragraph exceeds 1.3% of the Commonwealth's CAIR NOx Trading Budget, the Department will prorate the allocations based upon the following equation:

AA = [EA X (0.013 X BNA)] / TRA

where,

AA is the unit's prorated allocation,
EA is the adjusted allocation the unit may request under subparagraph (iii),
BNA is the total number of CAIR NOx allowances in the Commonwealth's CAIR NOx trading budget,
TRA is the total number of CAIR NOx allowances requested by all units requesting allowances under this paragraph.

(3) The Department will review each CAIR NOx allowance allocation request under this subsection and will allocate CAIR NOx allowances for each control period under a request as follows:

(i) The Department will accept an allowance allocation request only if the request meets, or is adjusted by the Department as necessary to meet, the requirements of this section.

(ii) On or after January 1 of the year of allocation, the Department will determine the sum of the CAIR NOx allowances requested.

(4) Up to 1.3% of the Commonwealth's CAIR NOx trading budget is available for allocation in each allocation cycle from 2011-2016 to allocate 2010-2015 allowances for the purpose of offsetting SO2 emissions from units described in paragraph (2). Beginning January 1, 2017, and for each allocation cycle thereafter, the units will no longer be allocated CAIR NOx allowances under paragraph (2). Any allowances remaining after this allocation will be allocated to units under subsection (c) during the next allocation cycle.

(5) Notwithstanding the provisions of paragraphs (2)¿(4), the Department may extend, terminate or otherwise modify the allocation of NOx allowances made available under this subsection for units exempted under section 405(g)(6)(a) of the Clean Air Act after providing notice in the Pennsylvania Bulletin and at least a 30-day public comment period.

(g) The Department will correct any errors in allocations made by the Department and discovered after final allocations are made but before the next allocation cycle, in the subsequent allocation cycle using future allowances that have not yet been allocated.

 # 075 [25 Pa. Code §145.222.]
CAIR NOx Ozone Season allowance allocations.

(a) Provisions not incorporated by reference. The requirements of 40 CFR 96.342 (relating to CAIR NOx Ozone Season allowance allocations) are not incorporated by reference. Instead of 40 CFR 96.342, the requirements in this section apply.

(b) Baseline heat input. Baseline heat input for each CAIR NOx Ozone Season unit will be converted as follows:

(1) A unit's control period heat input and a unit's status as coal-fired or oil-fired for the ozone season portion of a calendar year under this paragraph will be determined in one of the following two ways:

(i) In accordance with 40 CFR Part 75 (relating to continuous emission monitoring), to the extent that the unit was otherwise subject to the requirements of 40 CFR Part 75 for the control period.

(ii) Based on the best available data reported to the Department for the unit, to the extent the unit was not otherwise subject to the requirements of 40 CFR Part 75 for the year.

(2) Except as provided in subparagraphs (iv) and (v), a unit's converted control period heat input for the ozone season portion of a calendar year shall be determined as follows:

(i) The control period gross electrical output of the generators served by the unit multiplied by 7,900 Btu/kWh if the unit is coal-fired for the ozone season control period, and divided by 1,000,000 Btu/mmBtu.

(ii) Not Applicable

(iii) Not Applicable

(iv) Not Applicable

(v) Not Applicable

(vi) Calculations will be based on the best output data available on or before January 31 of the year the allocations are published. If unit level electrical or steam output data are not available from EIA, or submitted by this date by the owner or operator of the CAIR NOx Ozone Season unit, then heat input data for the period multiplied by 0.25 and converted to MWh will be used to determine total output.

(c) Not Applicable

(d) Proration of allowance allocations. The Department will allocate CAIR NOx Ozone Season allowances to each existing CAIR NOx Ozone Season unit and qualifying resource in an amount determined by multiplying the amount of CAIR NOx Ozone Season allowances in the Commonwealth's CAIR NOx Ozone Season trading budget available for allocation under subsection (c) by the ratio of the baseline heat input of the existing CAIR NOx Ozone Season unit or qualifying resource to the sums of the baseline heat input of existing CAIR NOx Ozone Season units and of the qualifying resources, rounding to the nearest whole allowance as appropriate.

(e) Not Applicable

(f) Not Applicable

(g) The Department will correct any errors in allocations made by the Department and discovered after final allocations are made but before the next allocation cycle, in the subsequent allocation cycle using future allowances that have not yet been allocated.

 # 076 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR NOXsource required to have a title V operating permit and each CAIR NOXunit required to have a title V operating permit at the source shall:
(i) Submit to the permitting authority a complete CAIR permit application under §97.122 in accordance with the deadlines specified in §97.121; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.
(2) The owners and operators of each CAIR NOXsource required to have a title V operating permit and each CAIR NOX unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

 # 077 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(d) Excess emissions requirements. If a CAIR NOXsource emits nitrogen oxides during any control period in excess of the CAIR NOXemissions limitation, then:
(1) The owners and operators of the source and each CAIR NOXunit at the source shall surrender the CAIR NOXallowances required for deduction under §97.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

 # 078 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(f) Liability. (1) Each CAIR NOXsource and each CAIR NOXunit shall meet the requirements of the CAIR NOXAnnual Trading Program.
(2) Any provision of the CAIR NOXAnnual Trading Program that applies to a CAIR NOXsource or the CAIR designated representative of a CAIR NOXsource shall also apply to the owners and operators of such source and of the CAIR NOXunits at the source.
(3) Any provision of the CAIR NOXAnnual Trading Program that applies to a CAIR NOXunit or the CAIR designated representative of a CAIR NOXunit shall also apply to the owners and operators of such unit.
(g) Effect on other authorities. No provision of the CAIR NOXAnnual Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §97.105 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NOXsource or CAIR NOXunit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

 # 079 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR SO2source required to have a title V operating permit and each CAIR SO2unit required to have a title V operating permit at the source shall:
(i) Submit to the permitting authority a complete CAIR permit application under §97.222 in accordance with the deadlines specified in §97.221; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.
(2) The owners and operators of each CAIR SO2source required to have a title V operating permit and each CAIR SO2unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

 # 080 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(d) Excess emissions requirements. If a CAIR SO2source emits sulfur dioxide during any control period in excess of the CAIR SO2emissions limitation, then:
(1) The owners and operators of the source and each CAIR SO2unit at the source shall surrender the CAIR SO2allowances required for deduction under §97.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

 # 081 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(f) Liability. (1) Each CAIR SO2source and each CAIR SO2unit shall meet the requirements of the CAIR SO2Trading Program.
(2) Any provision of the CAIR SO2Trading Program that applies to a CAIR SO2source or the CAIR designated representative of a CAIR SO2source shall also apply to the owners and operators of such source and of the CAIR SO2units at the source.
(3) Any provision of the CAIR SO2Trading Program that applies to a CAIR SO2unit or the CAIR designated representative of a CAIR SO2unit shall also apply to the owners and operators of such unit.
(g) Effect on other authorities. No provision of the CAIR SO2Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §97.205 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR SO2source or CAIR SO2unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

 # 082 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR NOXOzone Season source required to have a title V operating permit and each CAIR NOXOzone Season unit required to have a title V operating permit at the source shall:
(i) Submit to the permitting authority a complete CAIR permit application under §97.322 in accordance with the deadlines specified in §97.321; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.
(2) The owners and operators of each CAIR NOXOzone Season source required to have a title V operating permit and each CAIR NOXOzone Season unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

 # 083 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(d) Excess emissions requirements. If a CAIR NOXOzone Season source emits nitrogen oxides during any control period in excess of the CAIR NOXOzone Season emissions limitation, then:
(1) The owners and operators of the source and each CAIR NOXOzone Season unit at the source shall surrender the CAIR NOXOzone Season allowances required for deduction under §97.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

 # 084 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

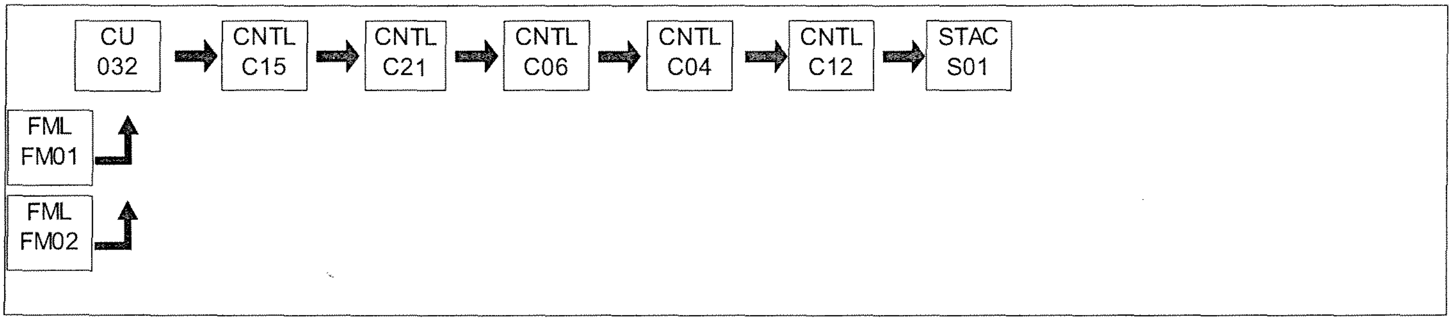
(f) Liability. (1) Each CAIR NOXOzone Season source and each CAIR NOXOzone Season unit shall meet the requirements of the CAIR NOXOzone Season Trading Program.
(2) Any provision of the CAIR NOXOzone Season Trading Program that applies to a CAIR NOXOzone Season source or the CAIR designated representative of a CAIR NOXOzone Season source shall also apply to the owners and operators of such source and of the CAIR NOXOzone Season units at the source.
(3) Any provision of the CAIR NOXOzone Season Trading Program that applies to a CAIR NOXOzone Season unit or the CAIR designated representative of a CAIR NOXOzone Season unit shall also apply to the owners and operators of such unit.
(g) Effect on other authorities. No provision of the CAIR NOXOzone Season Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §97.305 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NOXOzone Season source or CAIR NOXOzone Season unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 032 Source Name: UTILITY BOILER - UNIT 2

Source Capacity/Throughput: 1,345.000 MMBTU/HR



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.11]
Combustion units
No person may permit the emission into the outdoor atmosphere of particulate matter from the exhaust of Source ID 032 in excess of 0.1 pound per million British thermal units (lb/MMBtu) of heat input.

 # 002 [25 Pa. Code §123.22]
Combustion units
(a) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 032 in excess of the rate of 4 lb/MMBtu of heat input over any 1-hour period when firing #2 fuel oil.

(b) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 032 in excess of the pounds of SO2 per million British thermal units heat input as shown below when firing solid fossil fuels:

Thirty-day running average not to be exceeded at any time: 3.7 lb/MMBtu

Daily average not to be exceeded more than 2 days in any running 30-day period: 4.0 lb/MMBtu

Daily average not to be exceeded at any time: 4.8 lb/MMBtu

 # 003 [25 Pa. Code §127.441]
Operating permit terms and conditions.
The ammonia (NH3) emission rate from the exhaust of Source ID 032 shall not exceed 0.003 lb/MMBtu of heat input.

 # 004 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 through 129.95]

The nitrogen oxides emissions (NOx, expressed as NO2) from the exhaust of Source ID 032 shall not exceed 0.542 lb/MMBtu of heat input based on a 30 day rolling average.

 # 005 [25 Pa. Code §127.441]
Operating permit terms and conditions.
The ammonia slip resulting from the operation of each SNCR systems (IDs C20, C21, C22 and C23) associated with Source IDs 031, 032, 033 and 034 shall not exceed 5 ppmv corrected to 8% oxygen.

 # 006 [25 Pa. Code §127.531]
Special conditions related to acid rain.
[Additional authority for this permit condition is also derived from 40 CFR Section 70.6(a)(4)]

(a) The permittee shall not emit into the outdoor atmosphere, annual emissions of sulfur dioxide in excess of the number of allowances to emit sulfur dioxide that the permittee or designated representative holds for each affected source.

(b) The permittee shall not emit sulfur dioxide in a manner that would exceed applicable emission rates or standards, including ambient air quality standards.

(c) The permittee shall not use a sulfur dioxide allowance prior to the year for which the allowance is allocated.

(d) A limit will not be placed on the number of sulfur dioxide allowances held for a source. The permittee shall not, however, use allowances as a defense to noncompliance with other applicable requirements.

(e) The permittee shall account for all allowances in accordance with the procedures established in regulations promulgated under Title IV of the Clean Air Act.

 # 007 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(c) Nitrogen oxides emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NOXsource and each CAIR NOXunit at the source shall hold, in the source's compliance account, CAIR NOXallowances available for compliance deductions for the control period under §97.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NOXunits at the source, as determined in accordance with subpart HH of this part.
(2) A CAIR NOXunit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on January 1, 2009.
(3) A CAIR NOXallowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NOXallowance was allocated.
(4) CAIR NOXallowances shall be held in, deducted from, or transferred into or among CAIR NOXAllowance Tracking System accounts in accordance with subparts EE, FF, GG, and II of this part.
(5) A CAIR NOXallowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NOXAnnual Trading Program. No provision of the CAIR NOXAnnual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §97.105 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(6) A CAIR NOXallowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart EE, FF, GG, or II of this part, every allocation, transfer, or deduction of a CAIR NOXallowance to or from a CAIR NOXsource's compliance account is incorporated automatically in any CAIR permit of the source.

 # 008 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(c) Sulfur dioxide emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO2source and each CAIR SO2unit at the source shall hold, in the source's compliance account, a tonnage equivalent in CAIR SO2allowances available for compliance deductions for the control period, as determined in accordance with §97.254(a) and (b), not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO2units at the source, as determined in accordance with subpart HHH of this part.
(2) A CAIR SO2unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2010 or the deadline for meeting the unit(s monitor certification requirements under §97.270(b)(1),(2), or (5) and for each control period thereafter.
(3) A CAIR SO2allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR SO2allowance was allocated.
(4) CAIR SO2allowances shall be held in, deducted from, or transferred into or among CAIR SO2Allowance Tracking System accounts in accordance with subparts FFF, GGG, and III of this part.
(5) A CAIR SO2allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO2Trading Program. No provision of the CAIR SO2Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §97.205 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(6) A CAIR SO2allowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart FFF, GGG, or III of this part, every allocation, transfer, or deduction of

a CAIR SO2allowance to or from a CAIR SO2source's compliance account is incorporated automatically in any CAIR permit of the source.

 # 009 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(c) Nitrogen oxides ozone season emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall hold, in the source's compliance account, CAIR NOXOzone Season allowances available for compliance deductions for the control period under §97.354(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NOXOzone Season units at the source, as determined in accordance with subpart HHHH of this part.
(2) A CAIR NOXOzone Season unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §97.370(b)(1), (2), (3), or (7) and for each control period thereafter.
(3) A CAIR NOXOzone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NOXOzone Season allowance was allocated.
(4) CAIR NOXOzone Season allowances shall be held in, deducted from, or transferred into or among CAIR NOXOzone Season Allowance Tracking System accounts in accordance with subparts EEEE, FFFF, GGGG, and IIII of this part.
(5) A CAIR NOXOzone Season allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NOXOzone Season Trading Program. No provision of the CAIR NOXOzone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §97.305 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(6) A CAIR NOXOzone Season allowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart EEEE, FFFF, GGGG, or IIII of this part, every allocation, transfer, or deduction of a CAIR NOXOzone Season allowance to or from a CAIR NOXOzone Season source's compliance account is incorporated automatically in any CAIR permit of the source.

Fuel Restriction(s).

 # 010 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Section 123.22]

The sulfur content of the #2 and lighter fuel oil fired in Source ID 032 shall not exceed 0.5% (by weight).

 # 011 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from RFD condition approved April 8, 2002]

The only binding agents to be used in manufacturing the synthetic fuels used at the Shawville Station shall be soybean oil, Accretion Technologies FTH-100, Nalco 9838, Dow Covol 298 and Dow Covol 298-1 having the compositions identified in the materials submitted with the request for determination dated February 18, 2002 and approved on April 8, 2002. Additionally, the maximum application rate of the soybean oil shall be 1.0% by weight of the soybean oil/coal mixture and the maximum application rate of any of the other four binding agents shall be such that the maximum application rate of the combined non-water constituents contained in the binding agent shall never exceed 1.0% by weight of the binding agent/coal mixture.

II. TESTING REQUIREMENTS.

 # 012 [25 Pa. Code §127.441]
Operating permit terms and conditions.

All continuous emissions monitoring systems shall be tested in accordance with the applicable requirements specified in 25 Pa. Code Chapter 139, the Departments "Continuous Source Monitoring Manual" and 40 CFR Part 75.

 # 013 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable testing requirements specified in 25 Pa. Code Chapter 139 and the Departments "Source Testing Manual."

 # 014 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall conduct testing of the SNCR systems between January 1, 2014 and December 31, 2014 and every five years thereafter. The permittee shall conduct the following testing upon the exhaust of the utility boilers:

(a) Ammonia testing shall be conducted upon the exhausts of Source IDs 031 and 032, respectively, and the common exhaust of Source IDs 033 and 034 using EPA reference method stack testing or an alternative ammonia test method approved by the Department to determine ammonia slip levels and ammonia emissions from each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034.

(b) During the stack testing, the permittee shall measure and, record the gross megawatt load, NOx emissions and SNCR ammonia slip levels for each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034, and such information shall be provided in the stack test report submitted to the Department.

 # 015 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.6(b)(3)]

(a) Within 120 day of the issuance date of this permit, the permittee shall perform stack testing on the four utility boilers (Source IDs 031, 032, 033 and 034) to demonstrate compliance with the particulate matter emission limitation contained in this operating permit and obtain data to verify the validity of the Linear Regression equations and establish new Linear Regression equations (as approved by the Department) per the procedures in the 2007 CAM plan if the data warrants the establishment of new Linear Regression equations.

(b) Subsequent testing shall be performed on an approximate 2-year period, but in each case, no less than 20 months and no greater than 26 months following the date of the previous test.

(c) Stack testing shall be performed in accordance with the applicable provisions of 25 Pa. Code Chapter 139 (relating to sampling and testing) using test methods and procedures approved by the Department. Testing must be performed while the sources are operating under maximum normal operating conditions.

III. MONITORING REQUIREMENTS.

 # 016 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 123.25, 123.46, 123.51, 40 CFR Part 75]

The permittee shall install, calibrate, maintain and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxide emissions, carbon dioxide concentration (%CO2) and volumetric flow in accordance with all applicable requirements specified in, or established pursuant to: 25 Pa. Code Chapters 123 and 139, the Department's "Continuous Source Monitoring Manual" and 40 CFR Part 75.

 # 017 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable monitoring requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 018 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall install and maintain instrumentation to monitor and record the ammonia injection rate of the SNCR systems associated with Source IDs 031, 032, 033, and 034 on a continuous basis. Additionally, the permittee shall continuously monitor and record the gross megawatt load and NOx emissions associated with the boilers.

These records shall be retained for a minimum of five years and shall be presented to the Department upon request.

 # 019 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Authority for this condition is also derived from 40 CFR Part 64, relating to Compliance Assurance Monitoring (CAM)]

Compliance Assurance Monitoring (CAM) Protocol
(A) The purpose of this protocol is to outline procedures for the development, verification, operation, and ongoing maintenance of a continuous monitoring approach sufficient to reasonably assure that Source IDs 031, 032, 033, and 034 operate in compliance with the 0.1 lb/MMBtu particulate matter emission limitation.

(B) Monitoring designed and operated in accordance with this protocol satisfies the requirements of the CAM rule's monitoring design criteria in 40 CFR Section 64.3(a) and (b) pursuant to 40 CFR Section 64.3(d)(2).

I. CAM Indicators - Predicted Particulate Matter (PM) and Opacity of Exhaust
Measurement Approach - Predicted PM, in units of lb/MMBtu, using the % opacity measured by the COMS; the %CO2(w) measured by the CO2 CEMS; Unit's 3 and 4 gross megawatt load (MW) measured by the continuous gross megawatt load meter, data acquisition and handling system and Linear Regression equations (as approved by the Department).

II. CAM Indicator Parameters and Excursion
(A) As identified below, the predicted PM (1-hour average) is used as the CAM indicator paramater to comply with the requirements specified in 40 CFR Section 64.3(d)(3)(ii).

(B) The permittee shall assure the measured % opacity, %CO2(w), gross megawatt load and predicted PM are recorded in accordance to the requirements specified in 40 CFR Section 64.3(b)(4)(ii)

(C) The predicted PM for Units 1 and 2 shall be determined from the CAM indicators, including the predicted PM concentration, using the following equation:

lb/MMBtu = Y * (1 / 7000) * Fc * (100 / %CO2(w)) where,

Y = the predicted PM concentration (gr/scf) calculated by using the most recently approved Linear Regression equations
Fc = carbon-based F-factor
%CO2(w) = the %CO2 measured in accordance with item (d)(2) of this condiiton

(D) The predicted PM for Units 3 and 4 shall be determined from the CAM indicators, including the predicted PM concentration and emission apportionment factor (EAF) using the following equation:

lb/MMBtu = Y * (1 / 7000) * Fc * (100 / %CO2(w)) * EAF where,

Y = the predicted PM concentration (gr/scf) calculated by using the most recently approved Linear Regression equations,
Fc = carbon-based F-factor,
%CO2(w) = the %CO2 measured in accordance with item (d)(2) of this condiiton
EAF = each unit's average hourly gross megawatt load measured in accordance with item (d)(3) of this condition divided by the sum of hourly gross megawatt loads for Units 3 and 4.

(E) Each instance where the predicted PM rate (1-hour block average) exceeds 0.09 lb/MMBtu is defined to be an excursion.

(F) When an excursion occurs (the predicted PM rate, 1-hour block average exceeds 0.09 lb/MMBtu), the permittee shall initiate and comply with the requirements of 40 CFR Section 64.7(d).

III. Performance Criteria
(a) Data Representativeness
(1) The predicted PM using the % opacity measured by the COMS is proportional to the amount of filterable PM in the exhaust. Opacity shall be correlated to the PM concentration in accordance with the Investigative Program. The Investigative Program shall use the procedures specified in the 2007 CAM plan and the data obtained from the most recently approved stack tests for PM.

(b) Verification of Operational Status
(1) The operation of the COMS shall be verified by the presence of a valid opacity signal on the COMS readout; the results of the performance evaluations conducted as per 25 Pa. Code Chapter 139; and the presence of a valid result of the predicted PM rate (1-hour block average).

(c) QA/QC Practices
(1) The operation of the COMS and CEMS shall meet the requirements of 25 Pa. Code Chapter 139.

(2) See the condition under II. Testing Requirements for additional QA/QC practice requirements.

(d) Data Collection Procedures & Averaging Periods
(1) An electronic data handling and acquisition system (DAHS) shall collect data points representative of the opacity in the exhaust from the COMS approximately every 10 seconds. These % opacity readings shall be reduced to 1-minute averages and then to 1-hour averages.

(2) An electronic DAHS shall collect data points from the CO2 CEMS approximately every second. These %CO2(w) readings shall be reduced to 1-minute averages and then to 1-hour averages. Monitor response time shall be less than 15 minutes.

(3) An electronic DAHS shall collect data points from the continuous gross megawatt load meter installed on Unit 3 and 4 approximately every 15 minutes. The hourly average gross megawatt load meter for Unit 3 and 4 shall be calculated from the 15-minute data. Monitor response time shall be less than 15 minutes.

(4) An electronic DAHS shall calculate a minimum of 4 equally-spaced PM emission concentrations over a 1-hour period pursuant to the requirements of 40 CFR §64.3(b)(4)(ii). These PM emission concentrations will be calculated using the following equations. The following Linear Regression equations were obtained from the June 2005 testing program.

Y = (6.79E-05) * X^(2) for Unit 1

Y = (1.26E-05) * X^(2.5) for Unit 2

Y = (1.14E-05) * X^(2.3) for Unit 3 and 4 Common Stack,

Where Y = PM concentration (gr/scf)
X = Opacity (%)

(5) An electronic DAHS shall calculate a minimum of 4 equally-spaced PM rates, in units of lb/MMBtu over a 1-hour period pursuant to the requirements of 40 CFR §64.3(b)(4)(ii). These PM rates shall be calculated using the equations listed in this condition under II. (C) for Units 1 and 2 and II. (D) for Units 3 and 4. The 4 equally-spaced PM rates shall be reduced to 1-hour averages.

 # 020 [25 Pa. Code §145.213.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.170--96.175.

(a) The owner or operator of the CAIR NOx unit shall install, calibrate, maintain and operate a wattmeter, measure gross electrical output in megawatt-hours on a continuous basis and record the output of the wattmeter. If a generator is served by two or more units, the information to determine the heat input of each unit for that control period shall also be recorded, so as to allow each unit's share of the gross electrical output to be determined. If heat input data are used, the owner or

operator shall comply with the applicable provisions of 40 CFR Part 75 (relating to continuous emission monitoring).
(b) Not Applicable

 # 021 [25 Pa. Code §145.223.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.370--96.375.

(a) The owner or operator of the CAIR NOx Ozone Season unit shall install, calibrate, maintain and operate a wattmeter, measure gross electrical output in megawatt-hours on a continuous basis and record the output of the wattmeter. If a generator is served by two or more units, the information to determine the heat input of each unit for that control period shall also be recorded, so as to allow each unit's share of the gross electrical output to be determined. If heat input data are used, the owner or operator shall comply with the applicable provisions of 40 CFR Part 75 (relating to continuous emission monitoring).
(b) Not Applicable

 # 022 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.10]
Subpart B--Monitoring Provisions
General operating requirements.

The requirements in 40 CFR Section 75.10 apply.

 # 023 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.11]
Subpart B--Monitoring Provisions
Specific provisions for monitoring SO2 emissions (SO2 and flow monitors).

The requirements in 40 CFR 75.11 apply.

 # 024 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.12]
Subpart B--Monitoring Provisions
Specific provisions for monitoring NOx emissions (NOx and diluent gas monitors).

The requirements in 40 CFR 75.12(a) and (b) apply.

 # 025 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.13]
Subpart B--Monitoring Provisions
Specific provisions for monitoring CO2 emissions.

The requirements in 40 CFR 75.13(a) apply.

 # 026 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.14]
Subpart B--Monitoring Provisions
Specific provisions for monitoring opacity.

The requirements in 40 CFR 75.14(a) and (b) apply.

 # 027 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.2]
Subpart A--General
Applicability.

The requirements in 40 CFR 75.2 apply.

 # 028 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.20]
Subpart C--Operation and Maintenance Requirements
Certification and recertification procedures.

The requirements of 40 CFR 75.20 apply except for 40 CFR 75.20(e), (f) and (g).

 # 029 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.21]
Subpart C--Operation and Maintenance Requirements
Quality assurance and quality control requirements.

The requirements in 40 CFR 75.21(a)(1), (a)(2) and (a)(3) apply.

 # 030 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.22]
Subpart C--Operation and Maintenance Requirements
Reference test methods.

The requirements in 40 CFR 75.22 apply.

 # 031 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.24]
Subpart C--Operation and Maintenance Requirements
Out-of-control periods.

The requirements in 40 CFR 75.24 apply.

 # 032 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.30]
Subpart D--Missing Data Substitution Procedures
General provisions.

The requirements in 40 CFR 75.30 apply.

 # 033 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.4]
Subpart A--General
Compliance dates.

The requirements in 40 CFR 75.4(a)(3) apply.

 # 034 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.53]
Subpart F--Recordkeeping Requirements
Monitoring plan.

The requirements in 40 CFR 75.53 apply.

 # 035 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.60]
Subpart G--Reporting Requirements
General provisions.

The requirements in 40 CFR 75.60 apply.

 # 036 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.62]
Subpart G--Reporting Requirements
Monitoring plan.

The requirements of 40 CFR 75.62 apply.

 # 037 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.63]
Subpart G--Reporting Requirements
Initial certification or recertification application.

The requirements in 40 CFR 75.63 apply.

 # 038 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.64]
Subpart G--Reporting Requirements
Quarterly reports.

The requirements in 40 CFR 75.64 apply.

 # 039 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.65]
Subpart G--Reporting Requirements
Opacity reports.

The requirements in 40 CFR 75.65 apply.

 # 040 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR NOXsource and each CAIR NOXunit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HH of this part.
(2) The emissions measurements recorded and reported in accordance with subpart HH of this part shall be used to determine compliance by each CAIR NOXsource with the CAIR NOXemissions limitation under paragraph (c) of this section.

 # 041 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR SO2source and each CAIR SO2unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHH of this part.
(2) The emissions measurements recorded and reported in accordance with subpart HHH of this part shall be used to determine compliance by each CAIR SO2source with the CAIR SO2emissions limitation under paragraph (c) of this section.

 # 042 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of this part.
(2) The emissions measurements recorded and reported in accordance with subpart HHHH of this part shall be used to determine compliance by each CAIR NOXOzone Season source with the CAIR NOXOzone Season emissions limitation under paragraph (c) of this section.

IV. RECORDKEEPING REQUIREMENTS.

 # 043 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable recordkeeping requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 044 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall keep records of the data and calculations used to verify compliance with the particulate matter, sulfur oxides (SOx) and ammonia (NH3) emissions limitations for Source ID 032.

(b) The permittee shall keep records of the tests conducted or certification reports used to verify the sulfur content (percent by weight) of the fuel oil.

These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

 # 045 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

(a) The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95.

(b) The permittee shall keep records, including data which clearly demonstrates that the NOX emission limits for Source ID 032 are met.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

 # 046 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall keep records of the calculations, including ammonia emissions test reports, used to determine compliance with the SNCR ammonia slip emissions limitations for Source IDs 031, 032, 033 and 034. These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

 # 047 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall record all excursions and corrective actions taken in response to an excursion and the time elapsed until the corrective actions have been taken.

(b) The permittee shall keep records of all monitoring downtime incidents associated with the COMS and CO2 CEMS associated with Source IDs 031 through 034. The permittee shall also record the dates, times and durations, possible causes, and corrective actions taken for the incidents.

(c) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 048 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Compliance with the requirements in item (b) of this condition will assure compliance with the requirements of 40 CFR Section 64.7(c)]

[Additional authority items (a)-(b) of this condition is also derived from 40 CFR §64.6 & §64.3]

[Additional authority for permit conditions (c) is also derived from 40 CFR §64.9]

[Additional authority for permit condition (f) is also derived from 40 CFR §70.6(a)(3)(ii)(b)]

(a) The permittee shall use the following devices to monitor and record CAM indicators:
(i) The certified COMS that measure % opacity readings at a location downstream of each of the electrostatic precipitators (IDs C01, C04, C08, C09, C11, C12, C18, and C19).
(ii) The certified CEMS that measure the %CO2(w) at each of the stacks (ID S01 and S02)
(iii) Gross load meter to measure Unit's 3 and 4 gross megawatt load
(iv) Data Acquistion and handling systems (DAHS) to record all CAM indicators and calculate the predicted hourly PM rate, in units of lb/MMBtu.

(b) The permittee shall use the devices above to conduct monitoring and record the CAM indicators in accordance with the requirements of 40 CFR 64.3(b)(4)(ii).

(c) The permittee shall maintain supporting documentation to verify compliance with the requirements of 40 CFR Sections 64.9(a)(2)(i) and 64.7(b).

(d) The permittee shall maintain records of the operation of the devices above in order to report the information required in in 40 CFR Section 64.9(a)(2)(ii).

(e) The permittee shall maintain supporting information that verify that each response to an excursion meets the requirements of 40 CFR Section 64.7(d)

(f) The permittee shall keep all records for a period of five (5) years and shall make the records available to the Department upon request.

 # 049 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall keep records of all inspections, repairs, and maintenance performed on the devices used for Source IDs 031 through 034 CAM monitoring.

(b) The permittee shall record all excursions and corrective actions taken in response to an excursion and the time elapsed until the corrective actions have been taken.

(c) The permittee shall keep records of all monitoring downtime incidents associated with the devices used for Source IDs 031 through 034 CAM monitoring. The permittee shall also record the dates, times and durations, possible causes, and corrective actions taken for the downtime incidents.

(d) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 050 [25 Pa. Code §145.213.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.170--96.175.

(d) The owner or operator of a CAIR NOx unit shall maintain onsite the monitoring plan detailing the monitoring system and maintenance of the monitoring system, including quality assurance activities. The owner or operator of a CAIR NOx unit shall retain the monitoring plan for at least 5 years from the date that it is replaced by a new or revised monitoring plan. The owner or operator of a CAIR NOx Ozone Season unit shall provide the Department with a written copy of updates to the submitted monitoring plan, including a copy of the revised monitoring plan within 3 calendar months of making updates to the plan.
(e) The owner or operator of a CAIR NOx unit shall retain records for at least 5 years from the date the record is created or the data collected as required by subsections (a) and (b), and the reports submitted to the Department and the EPA in accordance with subsections (c) and (d).

 # 051 [25 Pa. Code §145.223.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.370--96.375.

(d) The owner or operator of a CAIR NOx Ozone Season unit shall maintain onsite the monitoring plan detailing the monitoring system and maintenance of the monitoring system, including quality assurance activities. The owner or operator of a CAIR NOx Ozone Season unit shall retain the monitoring plan for at least 5 years from the date that it is replaced by a new or revised monitoring plan. The owner or operator of a CAIR NOx Ozone Season unit shall provide the Department with a written copy of updates to the submitted monitoring plan, including a copy of the revised monitoring plan within 3 calendar months of making updates to the plan.
(e) The owner or operator of a CAIR NOx Ozone Season unit shall retain records for at least 5 years from the date the record is created or the data collected as required by subsections (a) and (b), and the reports submitted to the Department and the EPA in accordance with subsections (c) and (d).

 # 052 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR NOXsource and each CAIR NOXunit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §97.113 for the CAIR designated representative for the source and each CAIR NOXunit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.113 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subpart HH of this part, provided that to the extent that subpart HH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the

CAIR NOXAnnual Trading Program.
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NOXAnnual Trading Program or to demonstrate compliance with the requirements of the CAIR NOXAnnual Trading Program.

 # 053 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR SO2source and each CAIR SO2unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §97.213 for the CAIR designated representative for the source and each CAIR SO2unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.213 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subpart HHH of this part, provided that to the extent that subpart HHH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR SO2Trading Program.
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR SO2Trading Program or to demonstrate compliance with the requirements of the CAIR SO2Trading Program.

 # 054 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §97.313 for the CAIR designated representative for the source and each CAIR NOXOzone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.313 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subpart HHHH of this part, provided that to the extent that subpart HHHH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NOXOzone Season Trading Program.
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NOXOzone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NOXOzone Season Trading Program.

V. REPORTING REQUIREMENTS.

 # 055 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable reporting requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 056 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9 and Section 70.6(a)(3)(iii)(A)]

(a) The permittee shall submit reports to the Department on a semi-annual basis that include the records of all excursions and corrective actions taken, the dates, times, durations, and possible causes.

(b) The permittee shall submit reports to the Department on a semi-annual basis that include all monitoring downtime incidents, their dates, times and durations, possible causes, and corrective actions taken.

(c) The semi-annual reports shall be submitted to the Department no later than March 1 (for July 1 through December 31 of the previous year) and September 1 (for January 1 through June 30 of the current year).

 # 057 [25 Pa. Code §145.213.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.170--96.175.

(c) The designated representative of the units associated with Source IDs 031 through 034 shall submit to the Department an annual report showing monthly gross electrical output and monthly useful thermal energy from the unit. The report is due by January 31 for the preceding calendar year.

 # 058 [25 Pa. Code §145.223.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.370--96.375.

(c) The designated representative of the units associated with Source IDs 031 through 034 shall submit to the Department an annual report showing monthly gross electrical output and monthly useful thermal energy from the unit. The report is due by January 31 for the preceding calendar year.

 # 059 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(b)(2) The CAIR designated representative of a CAIR NOXsource and each CAIR NOXunit at the source shall submit the reports required under the CAIR NOXAnnual Trading Program, including those under subpart HH of this part.

 # 060 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(e)(2) The CAIR designated representative of a CAIR SO2source and each CAIR SO2unit at the source shall submit the reports required under the CAIR SO2Trading Program, including those under subpart HHH of this part.

 # 061 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(e)(2) The CAIR designated representative of a CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall submit the reports required under the CAIR NOXOzone Season Trading Program, including those under subpart HHHH of this part.

VI. WORK PRACTICE REQUIREMENTS.

 # 062 [25 Pa. Code §127.441]
Operating permit terms and conditions.

No reclaimed or waste oil or oil that contains any waste material shall be used as fuel in the lighter associated with the low NOX burners of Source ID 032.

 # 063 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 129.91]

The permittee shall maintain and operate Source ID 032 in accordance with the manufacturers specifications. This requirement shall be considered as VOC RACT for Source ID 032.

 # 064 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The SNCR systems (Control Device IDs C20, C21, C22, and C23) shall be operated in accordance with the manufacturer specifications and good air pollution control practices.

 # 065 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall comply with the requirements specified in 40 CFR Section 64.7(b) and (d), relating to Proper maintenance and Response to excursions, respectively.

VII. ADDITIONAL REQUIREMENTS.

 # 066 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source ID 032 is a 1954 vintage, Babcock Wilcox, dry bottom, front wall-fired, balanced draft, divided furnace drum type utility boiler with a rated heat input capacity of 1,345 MMBtu/hr. The boiler is fueled with pulverized bituminous coal/synfuel or #2 oil. The air contaminant emissions from the subject boiler shall be controlled by 16 Dual Register Low NOX (DRB-XCL) Babcock and Wilcox burners (Control Device ID C15), a NH3/SO3 injection flue gas conditioning system (Control Device ID C06) and a two stage Research Cottrell & Buell electrostatic precipitator (Control Device IDs C04 and C12).

The nitrogen oxides emissions from Source ID 032 may further be controlled by an Energy System Associates selective non-catalytic reduction system (Control Device ID C21).

 # 067 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Control Device IDs C20 and C21 associated with Source IDs 031 and 032 are considered SNCR system #1, which also consists of a storage tank and a recirculation pump. Control Device IDs C22 and C23 associated with Source IDs 033 & 034 are considered SNCR system #2, which also consists of a storage tank and a recirculation pump.

 # 068 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.8]

(a) The permittee shall develop and implement a Quality Improvement Plan (QIP) as expeditiously as practicable if any of the following occur:
(1) Six (6) excursions occur in a six (6) month reporting period.
(2) The Department determines after review of all reported information that the permittee has not responded acceptably to an excursion.

(b) The QIP should be developed within 60 days and the permittee shall provide a copy of the QIP to the Department. Furthermore, the permittee shall notify the Department if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(c) The permittee shall record actions taken to implement a QIP during a reporting period and all related actions including, but not limited to, inspections, repairs, and maintenance performed on the COMS, CO2 CEMS, gross megawatt load meter and DAHS.

(d) In accordance with 40 CFR Section 64.8, the QIP shall include procedures for evaluating the control performance problems. Based on the results of the evaluation procedures, the permittee shall modify the QIP and provide the Department with a copy, to include procedures for conducting more frequent, or improved, monitoring in conjunction with one or more of the following:
(1) Improved preventive maintenance practices,
(2) Process operation changes,

(3) Appropriate improvements to the control methods,
(4) Other steps appropriate to correct performance.

(e) Following implementation of a QIP, the Department will require reasonable revisions to the QIP if the plan has failed to either:
(1) Address the cause of the performance problems of the COMS, CO2 CEMS, gross megawatt load meter and/or DAHS.
(2) Provide adequate procedures for correcting the performance problems of the device(s) in an expeditious manner and according to good air pollution control practices.

(f) Implementation of a QIP shall not excuse the permittee from compliance with any existing emission limitation or standard or any existing monitoring, testing, reporting or recordkeeping requirements that may apply under any federal, state, or local laws or any other applicable requirements under the Clean Air Act.

 # 069 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source IDs 031 through 034 are subject to the CAM requirements of 40 CFR Part 64. The permittee shall comply with all applicable requirements of 40 CFR Sections 64.1 through 64.10.

 # 070 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source IDs 031 through 034 are defined to be affected sources in the National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (77 FR 9304). As the owner and operator of Source IDs 031 and 034, the permittee shall comply with all applicable requirements codified in 40 CFR Part 63 Subpart UUUUU (40 CFR §§ 63.9980 through 63.10042, including Tables and Appendices).

 # 071 [25 Pa. Code §127.531]
Special conditions related to acid rain.

The permittee shall comply with all applicable requirements and procedures established in regulations promulgated under Title IV of the Clean Air Act, including all applicable provisions from the following:

40 CFR Part 72	Permit Regulation
40 CFR Part 73	Sulfur Dioxide Allowance System
40 CFR Part 75	Continuous Emission Monitoring
40 CFR Part 76	Nitrogen Oxides Emission Reduction Program
40 CFR Part 77	Excess Emissions

Attached to Title V Operating Permit 17-00001 is the Phase II Title IV Operating Permit 17-00001 (Acid Rain Permit) in its entirety. The Acid Rain Permit was renewed on May 29, 2009 and is effective through December 31, 2012. Certain requirements from the Acid Rain permit have been reiterated in the body of the Title V operating permit for emphasis. The entire Acid Rain Permit is incorporated into the Title V operating permit by inclusion.

 # 072 [25 Pa. Code §145.204.]
Incorporation of Federal regulations by reference.

(a) Except as otherwise specified in this subchapter and herein, the provisions of the CAIR NOx Annual Trading Program, found in 40 CFR Part 96 (relating to NOx budget trading program and CAIR NOx and SO2 trading programs for State implementation plans), including all appendices, future amendments and supplements thereto, are incorporated by reference.
(b) Except as otherwise specified in this subchapter and herein, the provisions of the CAIR SO2 Trading Program, found in 40 CFR Part 96, including all appendices, future amendments and supplements thereto, are incorporated by reference.
(c) Except as otherwise specified in this subchapter and herein, the provisions of the CAIR NOx Ozone Season Trading Program, found in 40 CFR Part 96, including all appendices, future amendments and supplements thereto, are incorporated by reference.
(d) In the event of a conflict between Federal regulatory provisions incorporated by reference in this subchapter and Pennsylvania regulatory provisions, the provision expressly set out in this subchapter shall be followed unless the Federal provision is more stringent. Federal regulations that are cited in this subchapter or that are cross-referenced in the Federal regulations incorporated by reference include any Pennsylvania modifications made to those Federal regulations.

 # 073 [25 Pa. Code §145.205.]
Emission reduction credit provisions.

The following conditions shall be satisfied in order for the Department to issue a permit or plan approval to the owner or operator of a unit not subject to this subchapter that is relying on emission reduction credits (ERCs) or creditable emission reductions in an applicability determination under Chapter 127, Subchapter E (relating to new source review), or is seeking to enter into an emissions trade authorized under Chapter 127 (relating to construction, modification, reactivation and operation of sources), if the ERCs or creditable emission reductions were, or will be, generated by a unit subject to this subchapter.

(1) Prior to issuing the permit or plan approval, the Department will permanently reduce the Commonwealth's CAIR NOx trading budget or CAIR NOx Ozone Season trading budget, or both, as applicable, beginning with the sixth control period following the date the plan approval or permit to commence operations or increase emissions is issued. The Department will permanently reduce the applicable CAIR NOx budgets by an amount of allowances equal to the ERCs or creditable emission reductions relied upon in the applicability determination for the non-CAIR unit subject to Chapter 127, Subchapter E or in the amount equal to the emissions trade authorized under Chapter 127, as if these emissions had already been emitted.

(2) The permit or plan approval must prohibit the owner or operator from commencing operation or increasing emissions until the owner or operator of the CAIR unit generating the ERC or creditable emission reduction surrenders to the Department an amount of allowances equal to the ERCs or emission reduction credits relied upon in the applicability determination for the non-CAIR unit under Chapter 127, Subchapter E or the amount equal to the ERC trade authorized under Chapter 127, for each of the five consecutive control periods following the date the non-CAIR unit commences operation or increases emissions. The allowances surrendered must be of present or past vintage years.

 # 074 [25 Pa. Code §145.212.]
CAIR NOx allowance allocations.

(a) Provisions not incorporated by reference. The requirements of 40 CFR 96.142 (relating to CAIR NOx allowance allocations) are not incorporated by reference. Instead of 40 CFR 96.142, the requirements set forth in this section apply.

(b) Baseline heat input. Baseline heat input for each CAIR NOx unit will be converted as follows:

(1) A unit's control period heat input and a unit's status as coal-fired or oil-fired for a calendar year under this paragraph will be determined in one of the following two ways:

(i) In accordance with 40 CFR Part 75 (relating to continuous emission monitoring), to the extent that the unit was otherwise subject to 40 CFR Part 75 for the year.

(ii) Based on the best available data reported to the Department for the unit, to the extent the unit was not otherwise subject to the requirements of 40 CFR Part 75 for the year.

(2) Except as provided in subparagraphs (iv) and (v), a unit's converted control period heat input for a calendar year shall be determined as follows:

(i) The control period gross electrical output of the generators served by the unit multiplied by 7,900 Btu/kWh if the unit is coal-fired for the year, and divided by 1,000,000 Btu/mmBtu.

(ii) The control period gross electrical output of the generators served by the unit multiplied by 6,675 Btu/kWh if the unit is not coal-fired for the year, and divided by 1,000,000 Btu/mmBtu.

(iii) Not Applicable

(iv) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating or cooling purposes through the sequential use of energy, the total heat energy (in Btus) of the steam produced by the boiler during the annual control period, divided by 0.8 and by 1,000,000 Btu/mmBtu.

(v) Not Applicable

(vi) Calculations will be based on the best output data available on or before January 31 of the year the allocations are published. If unit level electrical or steam output data are not available from EIA, or submitted by this date by the owner or operator of the CAIR NOx unit, then heat input data for the period multiplied by 0.25 and converted to MWh will be used to determine total output.

(c) Existing unit, new unit and subsection (f)(1) qualifying resource allocation baseline. For each control period beginning with January 1, 2010, and each year thereafter, the Department will allocate to qualifying resources and CAIR NOx units, including CAIR NOx units issued allowances under subsection (e), a total amount of CAIR NOx allowances equal to the number of CAIR NOx allowances remaining in the Commonwealth's CAIR NOx trading budget under 40 CFR 96.140 (relating to State trading budgets) for those control periods using summed baseline heat input data as determined under subsections (b) and (f)(1) from a baseline year that is 6 calendar years before the control period.

(d) Proration of allowance allocations. The Department will allocate CAIR NOx allowances to each existing CAIR NOx unit and qualifying resource in an amount determined by multiplying the amount of CAIR NOx allowances in the Commonwealth's CAIR NOx trading budget available for allocation under subsection (c) by the ratio of the baseline heat input of the existing CAIR NOx unit or qualifying resource to the sum of the baseline heat input of existing CAIR NOx units and of the qualifying resources, rounding to the nearest whole allowance as appropriate.
(e) Allocations to new CAIR NOx units. By March 31, 2011, and March 31 each year thereafter, the Department will allocate CAIR NOx allowances under § 145.211(c) (relating to timing requirements for CAIR NOx allowance allocations) to CAIR NOx units equal to the previous year's emissions at each unit, unless the unit has been issued allowances of the previous year's vintage in a regular allocation under § 145.211(b). The Department will allocate CAIR NOx allowances under this subsection of a vintage year that is 5 years later than the year in which the emissions were generated. The number of CAIR NOx allowances allocated may not exceed the actual emission of the year preceding the year in which the Department makes the allocation. The allocation of these allowances to the new unit will not reduce the number of allowances the unit is entitled to receive under another provision of this subchapter.
(f) Allocations to qualifying resources and units exempted by section 405(g)(6)(a) of the Clean Air Act. For each control period beginning with 2010 and thereafter, the Department will allocate CAIR NOx allowances to qualifying resources under paragraph (1) in this Commonwealth that are not also allocated CAIR NOx allowances under another provision of this subchapter and to existing units under paragraph (2) that were exempted at any time under section 405(g)(6)(a) of the Clean Air Act (42 U.S.C.A. § 7651d(g)(6)(A)), regarding phase II SO2 requirements, and that commenced operation prior to January 1, 2000, but did not receive an allocation of SO2 allowances under the EPA's Acid Rain Program, as follows:
(1) The Department will allocate CAIR NOx allowances to a renewable energy qualifying resource or demand side management energy efficiency qualifying resource in accordance with subsections (c) and (d) upon receipt by the Department of an application, in writing, on or before June 30 of the year following the control period, except for vintage year 2011 and 2012 NOx allowance allocations whose application deadline will be prescribed by the Department, meeting the requirements of this paragraph. The number of allowances allocated to the qualifying resource will be determined by converting the certified quantity of electric energy production, useful thermal energy, and energy equivalent value of the measures approved under the Pennsylvania Alternative Energy Portfolio Standard to equivalent thermal energy. Equivalent thermal energy is a unit's baseline heat input for allocation purposes. The conversion rate for converting electrical energy to equivalent thermal energy is 3,413 Btu/kWh. To receive allowances under this subsection, the qualifying resource must have commenced operation after January 1, 2005, must be located in this Commonwealth and may not be a CAIR NOx unit. The following procedures apply:
(i) The owner of a qualifying renewable energy resource shall appoint a CAIR-authorized account representative and file a certificate of representation with the EPA and the Department.
(ii) The Department will transfer the allowances into an account designated by the owner's CAIR-authorized account representative of the qualifying resource, or into an account designated by an aggregator approved by the Pennsylvania Public Utility Commission or its designee.
(iii) The applicant shall provide the Department with the corresponding renewable energy certificate serial numbers.
(iv) At least one whole allowance must be generated per owner, operator or aggregator for an allowance to be issued.
(2) The Department will allocate CAIR NOx allowances to the owner or operator of a CAIR SO2 unit that commenced operation prior to January 1, 2000, that has not received an SO2 allocation for that compliance period, as follows:
(i) By January 31, 2011, and each year thereafter, the owner or operator of a unit may apply, in writing, to the Department under this subsection to receive extra CAIR NOx allowances.
(ii) The owner or operator may request under this subparagraph one CAIR NOx allowance for every 8 tons of SO2 emitted from a qualifying unit during the preceding control period. An owner or operator of a unit covered under this subparagraph that has opted into the Acid Rain Program may request one CAIR NOx allowance for every 8 tons of SO2 emissions that have not been covered by the SO2 allowances received as a result of opting into the Acid Rain Program.
(iii) If the original CAIR NOx allowance allocation for the unit for the control period exceeded the unit¿s actual emissions of NOx for the control period, the owner or operator shall also deduct the excess CAIR NOx allowances from the unit's request under subparagraph (ii). This amount is the unit's adjusted allocation and will be allocated unless the proration described in subparagraph (iv) applies.
(iv) The Department will make any necessary corrections and then sum the requests. If the total number of NOx allowances requested by all qualified units under this paragraph, as adjusted by subparagraph (iii), is less than 1.3% of the Commonwealth's CAIR NOx Trading Budget, the Department will allocate the corrected amounts. If the total number of NOx allowances requested by all qualified units under this paragraph exceeds 1.3% of the Commonwealth's CAIR NOx Trading Budget, the Department will prorate the allocations based upon the following equation:
AA = [EA X (0.013 X BNA)] / TRA
where,

AA is the unit's prorated allocation,
EA is the adjusted allocation the unit may request under subparagraph (iii),
BNA is the total number of CAIR NOx allowances in the Commonwealth's CAIR NOx trading budget,
TRA is the total number of CAIR NOx allowances requested by all units requesting allowances under this paragraph.

(3) The Department will review each CAIR NOx allowance allocation request under this subsection and will allocate CAIR NOx allowances for each control period under a request as follows:

(i) The Department will accept an allowance allocation request only if the request meets, or is adjusted by the Department as necessary to meet, the requirements of this section.

(ii) On or after January 1 of the year of allocation, the Department will determine the sum of the CAIR NOx allowances requested.

(4) Up to 1.3% of the Commonwealth's CAIR NOx trading budget is available for allocation in each allocation cycle from 2011-2016 to allocate 2010-2015 allowances for the purpose of offsetting SO2 emissions from units described in paragraph (2). Beginning January 1, 2017, and for each allocation cycle thereafter, the units will no longer be allocated CAIR NOx allowances under paragraph (2). Any allowances remaining after this allocation will be allocated to units under subsection (c) during the next allocation cycle.

(5) Notwithstanding the provisions of paragraphs (2)¿(4), the Department may extend, terminate or otherwise modify the allocation of NOx allowances made available under this subsection for units exempted under section 405(g)(6)(a) of the Clean Air Act after providing notice in the Pennsylvania Bulletin and at least a 30-day public comment period.

(g) The Department will correct any errors in allocations made by the Department and discovered after final allocations are made but before the next allocation cycle, in the subsequent allocation cycle using future allowances that have not yet been allocated.

 # 075 [25 Pa. Code §145.222.]
CAIR NOx Ozone Season allowance allocations.

(a) Provisions not incorporated by reference. The requirements of 40 CFR 96.342 (relating to CAIR NOx Ozone Season allowance allocations) are not incorporated by reference. Instead of 40 CFR 96.342, the requirements in this section apply.

(b) Baseline heat input. Baseline heat input for each CAIR NOx Ozone Season unit will be converted as follows:

(1) A unit's control period heat input and a unit's status as coal-fired or oil-fired for the ozone season portion of a calendar year under this paragraph will be determined in one of the following two ways:

(i) In accordance with 40 CFR Part 75 (relating to continuous emission monitoring), to the extent that the unit was otherwise subject to the requirements of 40 CFR Part 75 for the control period.

(ii) Based on the best available data reported to the Department for the unit, to the extent the unit was not otherwise subject to the requirements of 40 CFR Part 75 for the year.

(2) Except as provided in subparagraphs (iv) and (v), a unit's converted control period heat input for the ozone season portion of a calendar year shall be determined as follows:

(i) The control period gross electrical output of the generators served by the unit multiplied by 7,900 Btu/kWh if the unit is coal-fired for the ozone season control period, and divided by 1,000,000 Btu/mmBtu.

(ii) Not Applicable

(iii) Not Applicable

(iv) Not Applicable

(v) Not Applicable

(vi) Calculations will be based on the best output data available on or before January 31 of the year the allocations are published. If unit level electrical or steam output data are not available from EIA, or submitted by this date by the owner or operator of the CAIR NOx Ozone Season unit, then heat input data for the period multiplied by 0.25 and converted to MWh will be used to determine total output.

(c) Not Applicable

(d) Proration of allowance allocations. The Department will allocate CAIR NOx Ozone Season allowances to each existing CAIR NOx Ozone Season unit and qualifying resource in an amount determined by multiplying the amount of CAIR NOx Ozone Season allowances in the Commonwealth's CAIR NOx Ozone Season trading budget available for allocation under subsection (c) by the ratio of the baseline heat input of the existing CAIR NOx Ozone Season unit or qualifying resource to the sums of the baseline heat input of existing CAIR NOx Ozone Season units and of the qualifying resources, rounding to the nearest whole allowance as appropriate.

(e) Not Applicable

(f) Not Applicable

(g) The Department will correct any errors in allocations made by the Department and discovered after final allocations are made but before the next allocation cycle, in the subsequent allocation cycle using future allowances that have not yet been allocated.

 # 076 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR NOXsource required to have a title V operating permit and each CAIR NOXunit required to have a title V operating permit at the source shall:
(i) Submit to the permitting authority a complete CAIR permit application under §97.122 in accordance with the deadlines specified in §97.121; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.
(2) The owners and operators of each CAIR NOXsource required to have a title V operating permit and each CAIR NOX unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

 # 077 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(d) Excess emissions requirements. If a CAIR NOXsource emits nitrogen oxides during any control period in excess of the CAIR NOXemissions limitation, then:
(1) The owners and operators of the source and each CAIR NOXunit at the source shall surrender the CAIR NOXallowances required for deduction under §97.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

 # 078 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(f) Liability. (1) Each CAIR NOXsource and each CAIR NOXunit shall meet the requirements of the CAIR NOXAnnual Trading Program.
(2) Any provision of the CAIR NOXAnnual Trading Program that applies to a CAIR NOXsource or the CAIR designated representative of a CAIR NOXsource shall also apply to the owners and operators of such source and of the CAIR NOXunits at the source.
(3) Any provision of the CAIR NOXAnnual Trading Program that applies to a CAIR NOXunit or the CAIR designated representative of a CAIR NOXunit shall also apply to the owners and operators of such unit.
(g) Effect on other authorities. No provision of the CAIR NOXAnnual Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §97.105 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NOXsource or CAIR NOXunit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

 # 079 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR SO2source required to have a title V operating permit and each CAIR SO2unit required to have a title V operating permit at the source shall:
(i) Submit to the permitting authority a complete CAIR permit application under §97.222 in accordance with the deadlines specified in §97.221; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.
(2) The owners and operators of each CAIR SO2source required to have a title V operating permit and each CAIR SO2unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

 # 080 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(d) Excess emissions requirements. If a CAIR SO2source emits sulfur dioxide during any control period in excess of the CAIR SO2emissions limitation, then:
(1) The owners and operators of the source and each CAIR SO2unit at the source shall surrender the CAIR SO2allowances required for deduction under §97.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

 # 081 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(f) Liability. (1) Each CAIR SO2source and each CAIR SO2unit shall meet the requirements of the CAIR SO2Trading Program.
(2) Any provision of the CAIR SO2Trading Program that applies to a CAIR SO2source or the CAIR designated representative of a CAIR SO2source shall also apply to the owners and operators of such source and of the CAIR SO2units at the source.
(3) Any provision of the CAIR SO2Trading Program that applies to a CAIR SO2unit or the CAIR designated representative of a CAIR SO2unit shall also apply to the owners and operators of such unit.
(g) Effect on other authorities. No provision of the CAIR SO2Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §97.205 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR SO2source or CAIR SO2unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

 # 082 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR NOXOzone Season source required to have a title V operating permit and each CAIR NOXOzone Season unit required to have a title V operating permit at the source shall:
(i) Submit to the permitting authority a complete CAIR permit application under §97.322 in accordance with the deadlines specified in §97.321; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.
(2) The owners and operators of each CAIR NOXOzone Season source required to have a title V operating permit and each CAIR NOXOzone Season unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

 # 083 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(d) Excess emissions requirements. If a CAIR NOXOzone Season source emits nitrogen oxides during any control period in excess of the CAIR NOXOzone Season emissions limitation, then:
(1) The owners and operators of the source and each CAIR NOXOzone Season unit at the source shall surrender the CAIR NOXOzone Season allowances required for deduction under §97.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

 # 084 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

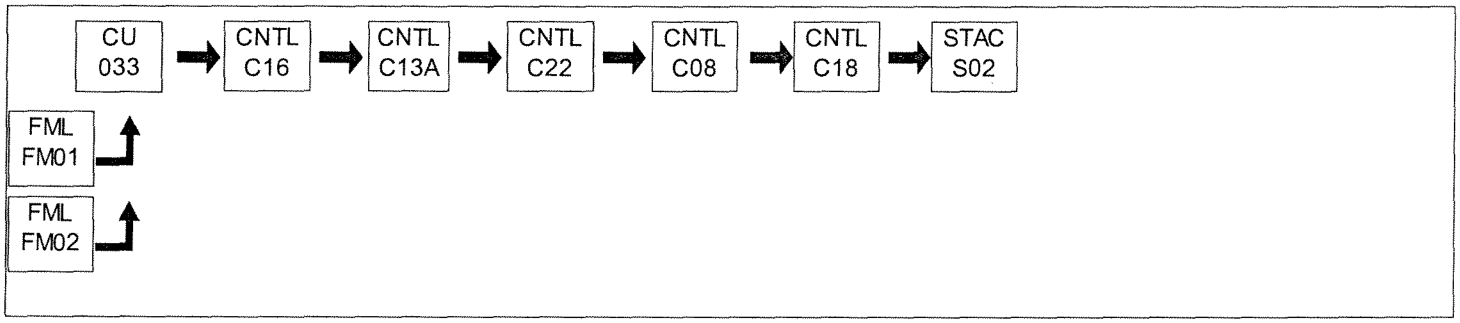
(f) Liability. (1) Each CAIR NOXOzone Season source and each CAIR NOXOzone Season unit shall meet the requirements of the CAIR NOXOzone Season Trading Program.
(2) Any provision of the CAIR NOXOzone Season Trading Program that applies to a CAIR NOXOzone Season source or the CAIR designated representative of a CAIR NOXOzone Season source shall also apply to the owners and operators of such source and of the CAIR NOXOzone Season units at the source.
(3) Any provision of the CAIR NOXOzone Season Trading Program that applies to a CAIR NOXOzone Season unit or the CAIR designated representative of a CAIR NOXOzone Season unit shall also apply to the owners and operators of such unit.
(g) Effect on other authorities. No provision of the CAIR NOXOzone Season Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §97.305 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NOXOzone Season source or CAIR NOXOzone Season unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 033 Source Name: UTILITY BOILER - UNIT 3

Source Capacity/Throughput: 1,790.000 MMBTU/HR



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.11]
Combustion units
No person may permit the emission into the outdoor atmosphere of particulate matter from the exhaust of Source ID 033 in excess of 0.1 pound per million British thermal units (lb/MMBtu) of heat input.

 # 002 [25 Pa. Code §123.22]
Combustion units
(a) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 033 in excess of the rate of 4 lb/MMBtu of heat input over any 1-hour period when firing #2 fuel oil.

(b) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 033 in excess of the pounds of SO2 per million British thermal units heat input as shown below when firing solid fossil fuels:

Thirty-day running average not to be exceeded at any time: 3.7 lb/MMBtu

Daily average not to be exceeded more than 2 days in any running 30-day period: 4.0 lb/MMBtu

Daily average not to be exceeded at any time: 4.8 lb/MMBtu

 # 003 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 through 129.95]

The nitrogen oxides emissions (NOx, expressed as NO2) from the exhaust of Source ID 033 shall not exceed 0.45 lb/MMBtu of heat input based on a 30 day rolling average.

 # 004 [25 Pa. Code §127.441]
Operating permit terms and conditions.
The ammonia slip resulting from the operation of each SNCR systems (IDs C20, C21, C22 and C23) associated with Source IDs 031, 032, 033 and 034 shall not exceed 5 ppmv corrected to 8% oxygen.

 # 005 [25 Pa. Code §127.531]
Special conditions related to acid rain.
[Additional authority for this permit condition is also derived from 40 CFR Section 70.6(a)(4)]

(a) The permittee shall not emit into the outdoor atmosphere, annual emissions of sulfur dioxide in excess of the number of allowances to emit sulfur dioxide that the permittee or designated representative holds for each affected source.

(b) The permittee shall not emit sulfur dioxide in a manner that would exceed applicable emission rates or standards, including ambient air quality standards.

(c) The permittee shall not use a sulfur dioxide allowance prior to the year for which the allowance is allocated.

(d) A limit will not be placed on the number of sulfur dioxide allowances held for a source. The permittee shall not, however, use allowances as a defense to noncompliance with other applicable requirements.

(e) The permittee shall account for all allowances in accordance with the procedures established in regulations promulgated under Title IV of the Clean Air Act.

 # 006 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(c) Nitrogen oxides emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NOXsource and each CAIR NOXunit at the source shall hold, in the source's compliance account, CAIR NOXallowances available for compliance deductions for the control period under §97.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NOXunits at the source, as determined in accordance with subpart HH of this part.
(2) A CAIR NOXunit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on January 1, 2009.
(3) A CAIR NOXallowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NOXallowance was allocated.
(4) CAIR NOXallowances shall be held in, deducted from, or transferred into or among CAIR NOXAllowance Tracking System accounts in accordance with subparts EE, FF, GG, and II of this part.
(5) A CAIR NOXallowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NOXAnnual Trading Program. No provision of the CAIR NOXAnnual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §97.105 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(6) A CAIR NOXallowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart EE, FF, GG, or II of this part, every allocation, transfer, or deduction of a CAIR NOXallowance to or from a CAIR NOXsource's compliance account is incorporated automatically in any CAIR permit of the source.

 # 007 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(c) Sulfur dioxide emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO2source and each CAIR SO2unit at the source shall hold, in the source's compliance account, a tonnage equivalent in CAIR SO2allowances available for compliance deductions for the control period, as determined in accordance with §97.254(a) and (b), not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO2units at the source, as determined in accordance with subpart HHH of this part.
(2) A CAIR SO2unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2010 or the deadline for meeting the unit(s monitor certification requirements under §97.270(b)(1),(2), or (5) and for each control period thereafter.
(3) A CAIR SO2allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR SO2allowance was allocated.
(4) CAIR SO2allowances shall be held in, deducted from, or transferred into or among CAIR SO2Allowance Tracking System accounts in accordance with subparts FFF, GGG, and III of this part.
(5) A CAIR SO2allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO2Trading Program. No provision of the CAIR SO2Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §97.205 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(6) A CAIR SO2allowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart FFF, GGG, or III of this part, every allocation, transfer, or deduction of a CAIR SO2allowance to or from a CAIR SO2source's compliance account is incorporated automatically in any CAIR permit of the source.

 # 008 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(c) Nitrogen oxides ozone season emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall hold, in the source's compliance account, CAIR NOXOzone Season allowances available for compliance deductions for the control period under §97.354(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NOXOzone Season units at the source, as determined in accordance with subpart HHHH of this part.

(2) A CAIR NOXOzone Season unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §97.370(b)(1), (2), (3), or (7) and for each control period thereafter.

(3) A CAIR NOXOzone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NOXOzone Season allowance was allocated.

(4) CAIR NOXOzone Season allowances shall be held in, deducted from, or transferred into or among CAIR NOXOzone Season Allowance Tracking System accounts in accordance with subparts EEEE, FFFF, GGGG, and IIII of this part.

(5) A CAIR NOXOzone Season allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NOXOzone Season Trading Program. No provision of the CAIR NOXOzone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §97.305 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(6) A CAIR NOXOzone Season allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart EEEE, FFFF, GGGG, or IIII of this part, every allocation, transfer, or deduction of a CAIR NOXOzone Season allowance to or from a CAIR NOXOzone Season source's compliance account is incorporated automatically in any CAIR permit of the source.

Fuel Restriction(s).

 # 009 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Section 123.22]

The sulfur content of the #2 and lighter fuel oil fired in Source ID 033 shall not exceed 0.5% (by weight).

 # 010 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from RFD condition approved April 8, 2002]

The only binding agents to be used in manufacturing the synthetic fuels used at the Shawville Station shall be soybean oil, Accretion Technologies FTH-100, Nalco 9838, Dow Covol 298 and Dow Covol 298-1 having the compositions identified in the materials submitted with the request for determination dated February 18, 2002 and approved on April 8, 2002. Additionally, the maximum application rate of the soybean oil shall be 1.0% by weight of the soybean oil/coal mixture and the maximum application rate of any of the other four binding agents shall be such that the maximum application rate of the combined non-water constituents contained in the binding agent shall never exceed 1.0% by weight of the binding agent/coal mixture.

II. TESTING REQUIREMENTS.

 # 011 [25 Pa. Code §127.441]
Operating permit terms and conditions.

All continuous emissions monitoring systems shall be tested in accordance with the applicable requirements specified in 25 Pa. Code Chapter 139, the Departments "Continuous Source Monitoring Manual" and 40 CFR Part 75.

 # 012 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable testing requirements specified in 25 Pa. Code Chapter 139 and the Departments "Source Testing Manual."

 # 013 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall conduct testing of the SNCR systems between January 1, 2014 and December 31, 2014 and every five years thereafter. The permittee shall conduct the following testing upon the exhaust of the utility boilers:

(a) Ammonia testing shall be conducted upon the exhausts of Source IDs 031 and 032, respectively, and the common exhaust of Source IDs 033 and 034 using EPA reference method stack testing or an alternative ammonia test method approved by the Department to determine ammonia slip levels and ammonia emissions from each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034.

(b) During the stack testing, the permittee shall measure and, record the gross megawatt load, NOx emissions and SNCR ammonia slip levels for each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034, and such information shall be provided in the stack test report submitted to the Department.

 # 014 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.6(b)(3)]

(a) Within 120 day of the issuance date of this permit, the permittee shall perform stack testing on the four utility boilers (Source IDs 031, 032, 033 and 034) to demonstrate compliance with the particulate matter emission limitation contained in this operating permit and obtain data to verify the validity of the Linear Regression equations and establish new Linear Regression equations (as approved by the Department) per the procedures in the 2007 CAM plan if the data warrants the establishment of new Linear Regression equations.

(b) Subsequent testing shall be performed on an approximate 2-year period, but in each case, no less than 20 months and no greater than 26 months following the date of the previous test.

(c) Stack testing shall be performed in accordance with the applicable provisions of 25 Pa. Code Chapter 139 (relating to sampling and testing) using test methods and procedures approved by the Department. Testing must be performed while the sources are operating under maximum normal operating conditions.

III. MONITORING REQUIREMENTS.

 # 015 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 123.25, 123.46, 123.51, 40 CFR Part 75]

The permittee shall install, calibrate, maintain and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxide emissions, carbon dioxide concentration (%CO2) and volumetric flow in accordance with all applicable requirements specified in, or established pursuant to: 25 Pa. Code Chapters 123 and 139, the Department's "Continuous Source Monitoring Manual" and 40 CFR Part 75.

 # 016 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable monitoring requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 017 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall install and maintain instrumentation to monitor and record the ammonia injection rate of the SNCR systems associated with Source IDs 031, 032, 033, and 034 on a continuous basis. Additionally, the permittee shall continuously monitor and record the gross megawatt load and NOx emissions associated with the boilers.

These records shall be retained for a minimum of five years and shall be presented to the Department upon request.

 # 018 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Authority for this condition is also derived from 40 CFR Part 64, relating to Compliance Assurance Monitoring (CAM)]

Compliance Assurance Monitoring (CAM) Protocol
(A) The purpose of this protocol is to outline procedures for the development, verification, operation, and ongoing maintenance of a continuous monitoring approach sufficient to reasonably assure that Source IDs 031, 032, 033, and 034 operate in compliance with the 0.1 lb/MMBtu particulate matter emission limitation.

(B) Monitoring designed and operated in accordance with this protocol satisfies the requirements of the CAM rule's monitoring design criteria in 40 CFR Section 64.3(a) and (b) pursuant to 40 CFR Section 64.3(d)(2).

I. CAM Indicators - Predicted Particulate Matter (PM) and Opacity of Exhaust
Measurement Approach - Predicted PM, in units of lb/MMBtu, using the % opacity measured by the COMS; the %CO2(w) measured by the CO2 CEMS; Unit's 3 and 4 gross megawatt load (MW) measured by the continuous gross megawatt load meter, data acquisition and handling system and Linear Regression equations (as approved by the Department).

II. CAM Indicator Parameters and Excursion
(A) As identified below, the predicted PM (1-hour average) is used as the CAM indicator paramater to comply with the requirements specified in 40 CFR Section 64.3(d)(3)(ii).

(B) The permittee shall assure the measured % opacity, %CO2(w), gross megawatt load and predicted PM are recorded in accordance to the requirements specified in 40 CFR Section 64.3(b)(4)(ii)

(C) The predicted PM for Units 1 and 2 shall be determined from the CAM indicators, including the predicted PM concentration, using the following equation:

lb/MMBtu = Y * (1 / 7000) * Fc * (100 / %CO2(w)) where,

Y = the predicted PM concentration (gr/scf) calculated by using the most recently approved Linear Regression equations
Fc = carbon-based F-factor
%CO2(w) = the %CO2 measured in accordance with item (d)(2) of this condiiton

(D) The predicted PM for Units 3 and 4 shall be determined from the CAM indicators, including the predicted PM concentration and emission apportionment factor (EAF) using the following equation:

lb/MMBtu = Y * (1 / 7000) * Fc * (100 / %CO2(w)) * EAF where,

Y = the predicted PM concentration (gr/scf) calculated by using the most recently approved Linear Regression equations,
Fc = carbon-based F-factor,
%CO2(w) = the %CO2 measured in accordance with item (d)(2) of this condiiton
EAF = each unit's average hourly gross megawatt load measured in accordance with item (d)(3) of this condition divided by the sum of hourly gross megawatt loads for Units 3 and 4.

(E) Each instance where the predicted PM rate (1-hour block average) exceeds 0.09 lb/MMBtu is defined to be an excursion.

(F) When an excursion occurs (the predicted PM rate, 1-hour block average exceeds 0.09 lb/MMBtu), the permittee shall initiate and comply with the requirements of 40 CFR Section 64.7(d).

III. Performance Criteria
(a) Data Representativeness

(1) The predicted PM using the % opacity measured by the COMS is proportional to the amount of filterable PM in the exhaust. Opacity shall be correlated to the PM concentration in accordance with the Investigative Program. The Investigative Program shall use the procedures specified in the 2007 CAM plan and the data obtained from the most recently approved stack tests for PM.

(b) Verification of Operational Status
(1) The operation of the COMS shall be verified by the presence of a valid opacity signal on the COMS readout; the results of the performance evaluations conducted as per 25 Pa. Code Chapter 139; and the presence of a valid result of the predicted PM rate (1-hour block average).

(c) QA/QC Practices
(1) The operation of the COMS and CEMS shall meet the requirements of 25 Pa. Code Chapter 139.

(2) See the condition under II. Testing Requirements for additional QA/QC practice requirements.

(d) Data Collection Procedures & Averaging Periods
(1) An electronic data handling and acquisition system (DAHS) shall collect data points representative of the opacity in the exhaust from the COMS approximately every 10 seconds. These % opacity readings shall be reduced to 1-minute averages and then to 1-hour averages.

(2) An electronic DAHS shall collect data points from the CO2 CEMS approximately every second. These %CO2(w) readings shall be reduced to 1-minute averages and then to 1-hour averages. Monitor response time shall be less than 15 minutes.

(3) An electronic DAHS shall collect data points from the continuous gross megawatt load meter installed on Unit 3 and 4 approximately every 15 minutes. The hourly average gross megawatt load meter for Unit 3 and 4 shall be calculated from the 15-minute data. Monitor response time shall be less than 15 minutes.

(4) An electronic DAHS shall calculate a minimum of 4 equally-spaced PM emission concentrations over a 1-hour period pursuant to the requirements of 40 CFR §64.3(b)(4)(ii). These PM emission concentrations will be calculated using the following equations. The following Linear Regression equations were obtained from the June 2005 testing program.

Y = (6.79E-05) * X^(2) for Unit 1

Y = (1.26E-05) * X^(2.5) for Unit 2

Y = (1.14E-05) * X^(2.3) for Unit 3 and 4 Common Stack,

Where Y = PM concentration (gr/scf)
X = Opacity (%)

(5) An electronic DAHS shall calculate a minimum of 4 equally-spaced PM rates, in units of lb/MMBtu over a 1-hour period pursuant to the requirements of 40 CFR §64.3(b)(4)(ii). These PM rates shall be calculated using the equations listed in this condition under II. (C) for Units 1 and 2 and II. (D) for Units 3 and 4. The 4 equally-spaced PM rates shall be reduced to 1-hour averages.

 # 019 [25 Pa. Code §145.213.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.170--96.175.

(a) The owner or operator of the CAIR NOx unit shall install, calibrate, maintain and operate a wattmeter, measure gross electrical output in megawatt-hours on a continuous basis and record the output of the wattmeter. If a generator is served by two or more units, the information to determine the heat input of each unit for that control period shall also be recorded, so as to allow each unit's share of the gross electrical output to be determined. If heat input data are used, the owner or operator shall comply with the applicable provisions of 40 CFR Part 75 (relating to continuous emission monitoring).
(b) Not Applicable

SECTION D. Source Level Requirements

 # 020 [25 Pa. Code §145.223.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.370--96.375.

(a) The owner or operator of the CAIR NOx Ozone Season unit shall install, calibrate, maintain and operate a wattmeter, measure gross electrical output in megawatt-hours on a continuous basis and record the output of the wattmeter. If a generator is served by two or more units, the information to determine the heat input of each unit for that control period shall also be recorded, so as to allow each unit's share of the gross electrical output to be determined. If heat input data are used, the owner or operator shall comply with the applicable provisions of 40 CFR Part 75 (relating to continuous emission monitoring).
(b) Not Applicable

 # 021 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.10]
Subpart B--Monitoring Provisions
General operating requirements.

The requirements in 40 CFR Section 75.10 apply.

 # 022 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.11]
Subpart B--Monitoring Provisions
Specific provisions for monitoring SO2 emissions (SO2 and flow monitors).

The requirements in 40 CFR 75.11 apply.

 # 023 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.12]
Subpart B--Monitoring Provisions
Specific provisions for monitoring NOx emissions (NOx and diluent gas monitors).

The requirements in 40 CFR 75.12(a) and (b) apply.

 # 024 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.13]
Subpart B--Monitoring Provisions
Specific provisions for monitoring CO2 emissions.

The requirements in 40 CFR 75.13(a) apply.

 # 025 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.14]
Subpart B--Monitoring Provisions
Specific provisions for monitoring opacity.

The requirements in 40 CFR 75.14(a) and (b) apply.

 # 026 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.2]
Subpart A--General
Applicability.

The requirements in 40 CFR 75.2 apply.

 # 027 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.20]
Subpart C--Operation and Maintenance Requirements
Certification and recertification procedures.

The requirements of 40 CFR 75.20 apply except for 40 CFR 75.20(e), (f) and (g).

 # 028 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.21]
Subpart C--Operation and Maintenance Requirements
Quality assurance and quality control requirements.

The requirements in 40 CFR 75.21(a)(1), (a)(2) and (a)(3) apply.

 # 029 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.22]
Subpart C--Operation and Maintenance Requirements
Reference test methods.

The requirements in 40 CFR 75.22 apply.

 # 030 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.24]
Subpart C--Operation and Maintenance Requirements
Out-of-control periods.

The requirements in 40 CFR 75.24 apply.

 # 031 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.30]
Subpart D--Missing Data Substitution Procedures
General provisions.

The requirements in 40 CFR 75.30 apply.

 # 032 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.4]
Subpart A--General
Compliance dates.

The requirements in 40 CFR 75.4(a)(3) apply.

 # 033 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.53]
Subpart F--Recordkeeping Requirements
Monitoring plan.

The requirements in 40 CFR 75.53 apply.

 # 034 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.60]
Subpart G--Reporting Requirements
General provisions.

The requirements in 40 CFR 75.60 apply.

 # 035 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.62]
Subpart G--Reporting Requirements
Monitoring plan.

The requirements of 40 CFR 75.62 apply.

 # 036 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.63]
Subpart G--Reporting Requirements
Initial certification or recertification application.

The requirements in 40 CFR 75.63 apply.

 # 037 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.64]
Subpart G--Reporting Requirements
Quarterly reports.

The requirements in 40 CFR 75.64 apply.

 # 038 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.65]
Subpart G--Reporting Requirements
Opacity reports.

The requirements in 40 CFR 75.65 apply.

 # 039 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR NOXsource and each CAIR NOXunit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HH of this part.
(2) The emissions measurements recorded and reported in accordance with subpart HH of this part shall be used to determine compliance by each CAIR NOXsource with the CAIR NOXemissions limitation under paragraph (c) of this section.

 # 040 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]

Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR SO2source and each CAIR SO2unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHH of this part.
(2) The emissions measurements recorded and reported in accordance with subpart HHH of this part shall be used to determine compliance by each CAIR SO2source with the CAIR SO2emissions limitation under paragraph (c) of this section.

 # 041 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of this part.
(2) The emissions measurements recorded and reported in accordance with subpart HHHH of this part shall be used to determine compliance by each CAIR NOXOzone Season source with the CAIR NOXOzone Season emissions limitation under paragraph (c) of this section.

IV. RECORDKEEPING REQUIREMENTS.

 # 042 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable recordkeeping requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 043 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

(a) The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95.

(b) The permittee shall keep records, including data which clearly demonstrates that the NOX emission limits for Source ID 033 are met.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

 # 044 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall keep records of the data and calculations used to verify compliance with the particulate matter and sulfur oxides (SOx) emissions limitations for Source ID 033.

(b) The permittee shall keep records of the tests conducted or certification reports used to verify the sulfur content (percent by weight) of the fuel oil.

These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

 # 045 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall keep records of the calculations, including ammonia emissions test reports, used to determine compliance with the SNCR ammonia slip emissions limitations for Source IDs 031, 032, 033 and 034. These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

 # 046 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall record all excursions and corrective actions taken in response to an excursion and the time elapsed until the corrective actions have been taken.

(b) The permittee shall keep records of all monitoring downtime incidents associated with the COMS and CO2 CEMS associated with Source IDs 031 through 034. The permittee shall also record the dates, times and durations, possible causes, and corrective actions taken for the incidents.

(c) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 047 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Compliance with the requirements in item (b) of this condition will assure compliance with the requirements of 40 CFR Section 64.7(c)]

[Additional authority items (a)-(b) of this condition is also derived from 40 CFR §64.6 & §64.3]

[Additional authority for permit conditions (c) is also derived from 40 CFR §64.9]

[Additional authority for permit condition (f) is also derived from 40 CFR §70.6(a)(3)(ii)(b)]

(a) The permittee shall use the following devices to monitor and record CAM indicators:
(i) The certified COMS that measure % opacity readings at a location downstream of each of the electrostatic precipitators (IDs C01, C04, C08, C09, C11, C12, C18, and C19).
(ii) The certified CEMS that measure the %CO2(w) at each of the stacks (ID S01 and S02)
(iii) Gross load meter to measure Unit's 3 and 4 gross megawatt load
(iv) Data Acquistion and handling systems (DAHS) to record all CAM indicators and calculate the predicted hourly PM rate, in units of lb/MMBtu.

(b) The permittee shall use the devices above to conduct monitoring and record the CAM indicators in accordance with the requirements of 40 CFR 64.3(b)(4)(ii).

(c) The permittee shall maintain supporting documentation to verify compliance with the requirements of 40 CFR Sections 64.9(a)(2)(i) and 64.7(b).

(d) The permittee shall maintain records of the operation of the devices above in order to report the information required in in 40 CFR Section 64.9(a)(2)(ii).

(e) The permittee shall maintain supporting information that verify that each response to an excursion meets the requirements of 40 CFR Section 64.7(d)

(f) The permittee shall keep all records for a period of five (5) years and shall make the records available to the Department upon request.

 # 048 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall keep records of all inspections, repairs, and maintenance performed on the devices used for Source IDs 031 through 034 CAM monitoring.

(b) The permittee shall record all excursions and corrective actions taken in response to an excursion and the time elapsed until the corrective actions have been taken.

(c) The permittee shall keep records of all monitoring downtime incidents associated with the devices used for Source IDs 031 through 034 CAM monitoring. The permittee shall also record the dates, times and durations, possible causes, and corrective actions taken for the downtime incidents.

(d) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 049 [25 Pa. Code §145.213.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.170--96.175.

(d) The owner or operator of a CAIR NOx unit shall maintain onsite the monitoring plan detailing the monitoring system and maintenance of the monitoring system, including quality assurance activities. The owner or operator of a CAIR NOx unit shall retain the monitoring plan for at least 5 years from the date that it is replaced by a new or revised monitoring plan. The owner or operator of a CAIR NOx Ozone Season unit shall provide the Department with a written copy of updates to the submitted monitoring plan, including a copy of the revised monitoring plan within 3 calendar months of making updates to the plan.
(e) The owner or operator of a CAIR NOx unit shall retain records for at least 5 years from the date the record is created or the data collected as required by subsections (a) and (b), and the reports submitted to the Department and the EPA in accordance with subsections (c) and (d).

 # 050 [25 Pa. Code §145.223.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.370--96.375.

(d) The owner or operator of a CAIR NOx Ozone Season unit shall maintain onsite the monitoring plan detailing the monitoring system and maintenance of the monitoring system, including quality assurance activities. The owner or operator of a CAIR NOx Ozone Season unit shall retain the monitoring plan for at least 5 years from the date that it is replaced by a new or revised monitoring plan. The owner or operator of a CAIR NOx Ozone Season unit shall provide the Department with a written copy of updates to the submitted monitoring plan, including a copy of the revised monitoring plan within 3 calendar months of making updates to the plan.
(e) The owner or operator of a CAIR NOx Ozone Season unit shall retain records for at least 5 years from the date the record is created or the data collected as required by subsections (a) and (b), and the reports submitted to the Department and the EPA in accordance with subsections (c) and (d).

 # 051 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR NOXsource and each CAIR NOXunit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §97.113 for the CAIR designated representative for the source and each CAIR NOXunit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.113 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subpart HH of this part, provided that to the extent that subpart HH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the

CAIR NOXAnnual Trading Program.
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NOXAnnual Trading Program or to demonstrate compliance with the requirements of the CAIR NOXAnnual Trading Program.

 # 052 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR SO2source and each CAIR SO2unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §97.213 for the CAIR designated representative for the source and each CAIR SO2unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.213 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subpart HHH of this part, provided that to the extent that subpart HHH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR SO2Trading Program.
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR SO2Trading Program or to demonstrate compliance with the requirements of the CAIR SO2Trading Program.

 # 053 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created..This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §97.313 for the CAIR designated representative for the source and each CAIR NOXOzone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.313 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subpart HHHH of this part, provided that to the extent that subpart HHHH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NOXOzone Season Trading Program.
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NOXOzone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NOXOzone Season Trading Program.

V. REPORTING REQUIREMENTS.

 # 054 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable reporting requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 055 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9 and Section 70.6(a)(3)(iii)(A)]

(a) The permittee shall submit reports to the Department on a semi-annual basis that include the records of all excursions and corrective actions taken, the dates, times, durations, and possible causes.

(b) The permittee shall submit reports to the Department on a semi-annual basis that include all monitoring downtime incidents, their dates, times and durations, possible causes, and corrective actions taken.

(c) The semi-annual reports shall be submitted to the Department no later than March 1 (for July 1 through December 31 of the previous year) and September 1 (for January 1 through June 30 of the current year).

 # 056 [25 Pa. Code §145.213.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.170--96.175.

(c) The designated representative of the units associated with Source IDs 031 through 034 shall submit to the Department an annual report showing monthly gross electrical output and monthly useful thermal energy from the unit. The report is due by January 31 for the preceding calendar year.

 # 057 [25 Pa. Code §145.223.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.370--96.375.

(c) The designated representative of the units associated with Source IDs 031 through 034 shall submit to the Department an annual report showing monthly gross electrical output and monthly useful thermal energy from the unit. The report is due by January 31 for the preceding calendar year.

 # 058 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(b)(2) The CAIR designated representative of a CAIR NOXsource and each CAIR NOXunit at the source shall submit the reports required under the CAIR NOXAnnual Trading Program, including those under subpart HH of this part.

 # 059 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(e)(2) The CAIR designated representative of a CAIR SO2source and each CAIR SO2unit at the source shall submit the reports required under the CAIR SO2Trading Program, including those under subpart HHH of this part.

 # 060 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(e)(2) The CAIR designated representative of a CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall submit the reports required under the CAIR NOXOzone Season Trading Program, including those under subpart HHHH of this part.

VI. WORK PRACTICE REQUIREMENTS.

 # 061 [25 Pa. Code §127.441]
Operating permit terms and conditions.

No reclaimed or waste oil or oil that contains any waste material shall be used as fuel in the lighter associated with the low NOX burners of Source ID 033.

 # 062 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 129.91]

The permittee shall maintain and operate Source ID 033 in accordance with the manufacturers specifications. This requirement shall be considered as VOC RACT for Source ID 033.

 # 063 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The SNCR systems (Control Device IDs C20, C21, C22, and C23) shall be operated in accordance with the manufacturer specifications and good air pollution control practices.

 # 064 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall comply with the requirements specified in 40 CFR Section 64.7(b) and (d), relating to Proper maintenance and Response to excursions, respectively.

VII. ADDITIONAL REQUIREMENTS.

 # 065 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Sources ID 033 and 034 (Unit 3 and 4) may be used for the incineration/evaporation of liquid wastes resulting from the chemical cleaning of boiler tubes with non-hazardous (HAP) and non-VOC containing liquid cleaning solutions.

 # 066 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source ID 033 is a 1959 vintage, Combustion Engineering, tangential fired, balanced draft, divided furnace, with a combined circulation, radiant, reheat boiler with a rated heat input capacity of 1,790 MMBtu/hr. The boiler is fueled with pulverized bituminous coal/synfuel or #2 oil. The air contaminant emissions from the subject boiler shall be controlled by low NOX burners {LNCFSIII} (Control Device ID C16), overfire air (Control Device ID C13A) and a two stage Research Cottrell & Buell electrostatic precipitator (Control Device IDs C08 and C18).

The nitrogen oxides emissions from Source ID 033 may further be controlled by an Energy System Associates selective non-catalytic reduction system (Control Device ID C22).

 # 067 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Control Device IDs C20 and C21 associated with Source IDs 031 and 032 are considered SNCR system #1, which also consists of a storage tank and a recirculation pump. Control Device IDs C22 and C23 associated with Source IDs 033 & 034 are considered SNCR system #2, which also consists of a storage tank and a recirculation pump.

 # 068 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.8]

(a) The permittee shall develop and implement a Quality Improvement Plan (QIP) as expeditiously as practicable if any of the following occur:
(1) Six (6) excursions occur in a six (6) month reporting period.
(2) The Department determines after review of all reported information that the permittee has not responded acceptably to an excursion.

(b) The QIP should be developed within 60 days and the permittee shall provide a copy of the QIP to the Department. Furthermore, the permittee shall notify the Department if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(c) The permittee shall record actions taken to implement a QIP during a reporting period and all related actions including, but not limited to, inspections, repairs, and maintenance performed on the COMS, CO2 CEMS, gross megawatt load meter and DAHS.

(d) In accordance with 40 CFR Section 64.8, the QIP shall include procedures for evaluating the control performance

problems. Based on the results of the evaluation procedures, the permittee shall modify the QIP and provide the Department with a copy, to include procedures for conducting more frequent, or improved, monitoring in conjunction with one or more of the following:
(1) Improved preventive maintenance practices,
(2) Process operation changes,
(3) Appropriate improvements to the control methods,
(4) Other steps appropriate to correct performance.

(e) Following implementation of a QIP, the Department will require reasonable revisions to the QIP if the plan has failed to either:
(1) Address the cause of the performance problems of the COMS, CO2 CEMS, gross megawatt load meter and/or DAHS.
(2) Provide adequate procedures for correcting the performance problems of the device(s) in an expeditious manner and according to good air pollution control practices.

(f) Implementation of a QIP shall not excuse the permittee from compliance with any existing emission limitation or standard or any existing monitoring, testing, reporting or recordkeeping requirements that may apply under any federal, state, or local laws or any other applicable requirements under the Clean Air Act.

 # 069 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source IDs 031 through 034 are subject to the CAM requirements of 40 CFR Part 64. The permittee shall comply with all applicable requirements of 40 CFR Sections 64.1 through 64.10.

 # 070 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source IDs 031 through 034 are defined to be affected sources in the National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (77 FR 9304). As the owner and operator of Source IDs 031 and 034, the permittee shall comply with all applicable requirements codified in 40 CFR Part 63 Subpart UUUUU (40 CFR §§ 63.9980 through 63.10042, including Tables and Appendices).

 # 071 [25 Pa. Code §127.531]
Special conditions related to acid rain.

The permittee shall comply with all applicable requirements and procedures established in regulations promulgated under Title IV of the Clean Air Act, including all applicable provisions from the following:

40 CFR Part 72	Permit Regulation
40 CFR Part 73	Sulfur Dioxide Allowance System
40 CFR Part 75	Continuous Emission Monitoring
40 CFR Part 76	Nitrogen Oxides Emission Reduction Program
40 CFR Part 77	Excess Emissions

Attached to Title V Operating Permit 17-00001 is the Phase II Title IV Operating Permit 17-00001 (Acid Rain Permit) in its entirety. The Acid Rain Permit was renewed on May 29, 2009 and is effective through December 31, 2012. Certain requirements from the Acid Rain permit have been reiterated in the body of the Title V operating permit for emphasis. The entire Acid Rain Permit is incorporated into the Title V operating permit by inclusion.

 # 072 [25 Pa. Code §145.204.]
Incorporation of Federal regulations by reference.

(a) Except as otherwise specified in this subchapter and herein, the provisions of the CAIR NOx Annual Trading Program, found in 40 CFR Part 96 (relating to NOx budget trading program and CAIR NOx and SO2 trading programs for State implementation plans), including all appendices, future amendments and supplements thereto, are incorporated by reference.
(b) Except as otherwise specified in this subchapter and herein, the provisions of the CAIR SO2 Trading Program, found in 40 CFR Part 96, including all appendices, future amendments and supplements thereto, are incorporated by reference.
(c) Except as otherwise specified in this subchapter and herein, the provisions of the CAIR NOx Ozone Season Trading Program, found in 40 CFR Part 96, including all appendices, future amendments and supplements thereto, are

incorporated by reference.

(d) In the event of a conflict between Federal regulatory provisions incorporated by reference in this subchapter and Pennsylvania regulatory provisions, the provision expressly set out in this subchapter shall be followed unless the Federal provision is more stringent. Federal regulations that are cited in this subchapter or that are cross-referenced in the Federal regulations incorporated by reference include any Pennsylvania modifications made to those Federal regulations.

 # 073 [25 Pa. Code §145.205.]
Emission reduction credit provisions.

The following conditions shall be satisfied in order for the Department to issue a permit or plan approval to the owner or operator of a unit not subject to this subchapter that is relying on emission reduction credits (ERCs) or creditable emission reductions in an applicability determination under Chapter 127, Subchapter E (relating to new source review), or is seeking to enter into an emissions trade authorized under Chapter 127 (relating to construction, modification, reactivation and operation of sources), if the ERCs or creditable emission reductions were, or will be, generated by a unit subject to this subchapter.

(1) Prior to issuing the permit or plan approval, the Department will permanently reduce the Commonwealth's CAIR NOx trading budget or CAIR NOx Ozone Season trading budget, or both, as applicable, beginning with the sixth control period following the date the plan approval or permit to commence operations or increase emissions is issued. The Department will permanently reduce the applicable CAIR NOx budgets by an amount of allowances equal to the ERCs or creditable emission reductions relied upon in the applicability determination for the non-CAIR unit subject to Chapter 127, Subchapter E or in the amount equal to the emissions trade authorized under Chapter 127, as if these emissions had already been emitted.

(2) The permit or plan approval must prohibit the owner or operator from commencing operation or increasing emissions until the owner or operator of the CAIR unit generating the ERC or creditable emission reduction surrenders to the Department an amount of allowances equal to the ERCs or emission reduction credits relied upon in the applicability determination for the non-CAIR unit under Chapter 127, Subchapter E or the amount equal to the ERC trade authorized under Chapter 127, for each of the five consecutive control periods following the date the non-CAIR unit commences operation or increases emissions. The allowances surrendered must be of present or past vintage years.

 # 074 [25 Pa. Code §145.212.]
CAIR NOx allowance allocations.

(a) Provisions not incorporated by reference. The requirements of 40 CFR 96.142 (relating to CAIR NOx allowance allocations) are not incorporated by reference. Instead of 40 CFR 96.142, the requirements set forth in this section apply.

(b) Baseline heat input. Baseline heat input for each CAIR NOx unit will be converted as follows:

(1) A unit's control period heat input and a unit's status as coal-fired or oil-fired for a calendar year under this paragraph will be determined in one of the following two ways:

(i) In accordance with 40 CFR Part 75 (relating to continuous emission monitoring), to the extent that the unit was otherwise subject to 40 CFR Part 75 for the year.

(ii) Based on the best available data reported to the Department for the unit, to the extent the unit was not otherwise subject to the requirements of 40 CFR Part 75 for the year.

(2) Except as provided in subparagraphs (iv) and (v), a unit's converted control period heat input for a calendar year shall be determined as follows:

(i) The control period gross electrical output of the generators served by the unit multiplied by 7,900 Btu/kWh if the unit is coal-fired for the year, and divided by 1,000,000 Btu/mmBtu.

(ii) The control period gross electrical output of the generators served by the unit multiplied by 6,675 Btu/kWh if the unit is not coal-fired for the year, and divided by 1,000,000 Btu/mmBtu.

(iii) Not Applicable

(iv) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating or cooling purposes through the sequential use of energy, the total heat energy (in Btus) of the steam produced by the boiler during the annual control period, divided by 0.8 and by 1,000,000 Btu/mmBtu.

(v) Not Applicable

(vi) Calculations will be based on the best output data available on or before January 31 of the year the allocations are published. If unit level electrical or steam output data are not available from EIA, or submitted by this date by the owner or operator of the CAIR NOx unit, then heat input data for the period multiplied by 0.25 and converted to MWh will be used to determine total output.

(c) Existing unit, new unit and subsection (f)(1) qualifying resource allocation baseline. For each control period beginning with January 1, 2010, and each year thereafter, the Department will allocate to qualifying resources and CAIR NOx units, including CAIR NOx units issued allowances under subsection (e), a total amount of CAIR NOx allowances equal to the number of CAIR NOx allowances remaining in the Commonwealth's CAIR NOx trading budget under 40 CFR 96.140 (relating to State trading budgets) for those control periods using summed baseline heat input data as determined under subsections (b) and (f)(1) from a baseline year that is 6 calendar years before the control period.

(d) Proration of allowance allocations. The Department will allocate CAIR NOx allowances to each existing CAIR NOx unit and qualifying resource in an amount determined by multiplying the amount of CAIR NOx allowances in the Commonwealth's CAIR NOx trading budget available for allocation under subsection (c) by the ratio of the baseline heat input of the existing CAIR NOx unit or qualifying resource to the sum of the baseline heat input of existing CAIR NOx units and of the qualifying resources, rounding to the nearest whole allowance as appropriate.

(e) Allocations to new CAIR NOx units. By March 31, 2011, and March 31 each year thereafter, the Department will allocate CAIR NOx allowances under § 145.211(c) (relating to timing requirements for CAIR NOx allowance allocations) to CAIR NOx units equal to the previous year's emissions at each unit, unless the unit has been issued allowances of the previous year's vintage in a regular allocation under § 145.211(b). The Department will allocate CAIR NOx allowances under this subsection of a vintage year that is 5 years later than the year in which the emissions were generated. The number of CAIR NOx allowances allocated may not exceed the actual emission of the year preceding the year in which the Department makes the allocation. The allocation of these allowances to the new unit will not reduce the number of allowances the unit is entitled to receive under another provision of this subchapter.

(f) Allocations to qualifying resources and units exempted by section 405(g)(6)(a) of the Clean Air Act. For each control period beginning with 2010 and thereafter, the Department will allocate CAIR NOx allowances to qualifying resources under paragraph (1) in this Commonwealth that are not also allocated CAIR NOx allowances under another provision of this subchapter and to existing units under paragraph (2) that were exempted at any time under section 405(g)(6)(a) of the Clean Air Act (42 U.S.C.A. § 7651d(g)(6)(A)), regarding phase II SO2 requirements, and that commenced operation prior to January 1, 2000, but did not receive an allocation of SO2 allowances under the EPA's Acid Rain Program, as follows:

(1) The Department will allocate CAIR NOx allowances to a renewable energy qualifying resource or demand side management energy efficiency qualifying resource in accordance with subsections (c) and (d) upon receipt by the Department of an application, in writing, on or before June 30 of the year following the control period, except for vintage year 2011 and 2012 NOx allowance allocations whose application deadline will be prescribed by the Department, meeting the requirements of this paragraph. The number of allowances allocated to the qualifying resource will be determined by converting the certified quantity of electric energy production, useful thermal energy, and energy equivalent value of the measures approved under the Pennsylvania Alternative Energy Portfolio Standard to equivalent thermal energy. Equivalent thermal energy is a unit's baseline heat input for allocation purposes. The conversion rate for converting electrical energy to equivalent thermal energy is 3,413 Btu/kWh. To receive allowances under this subsection, the qualifying resource must have commenced operation after January 1, 2005, must be located in this Commonwealth and may not be a CAIR NOx unit. The following procedures apply:

(i) The owner of a qualifying renewable energy resource shall appoint a CAIR-authorized account representative and file a certificate of representation with the EPA and the Department.

(ii) The Department will transfer the allowances into an account designated by the owner's CAIR-authorized account representative of the qualifying resource, or into an account designated by an aggregator approved by the Pennsylvania Public Utility Commission or its designee.

(iii) The applicant shall provide the Department with the corresponding renewable energy certificate serial numbers.

(iv) At least one whole allowance must be generated per owner, operator or aggregator for an allowance to be issued.

(2) The Department will allocate CAIR NOx allowances to the owner or operator of a CAIR SO2 unit that commenced operation prior to January 1, 2000, that has not received an SO2 allocation for that compliance period, as follows:

(i) By January 31, 2011, and each year thereafter, the owner or operator of a unit may apply, in writing, to the Department under this subsection to receive extra CAIR NOx allowances.

(ii) The owner or operator may request under this subparagraph one CAIR NOx allowance for every 8 tons of SO2 emitted from a qualifying unit during the preceding control period. An owner or operator of a unit covered under this subparagraph that has opted into the Acid Rain Program may request one CAIR NOx allowance for every 8 tons of SO2 emissions that have not been covered by the SO2 allowances received as a result of opting into the Acid Rain Program.

(iii) If the original CAIR NOx allowance allocation for the unit for the control period exceeded the unit¿s actual emissions of NOx for the control period, the owner or operator shall also deduct the excess CAIR NOx allowances from the unit's request under subparagraph (ii). This amount is the unit's adjusted allocation and will be allocated unless the proration described in subparagraph (iv) applies.

(iv) The Department will make any necessary corrections and then sum the requests. If the total number of NOx allowances requested by all qualified units under this paragraph, as adjusted by subparagraph (iii), is less than 1.3% of the Commonwealth's CAIR NOx Trading Budget, the Department will allocate the corrected amounts. If the total number of NOx allowances requested by all qualified units under this paragraph exceeds 1.3% of the Commonwealth's CAIR NOx Trading Budget, the Department will prorate the allocations based upon the following equation:

AA = [EA X (0.013 X BNA)] / TRA

where,

AA is the unit's prorated allocation,

EA is the adjusted allocation the unit may request under subparagraph (iii),

BNA is the total number of CAIR NOx allowances in the Commonwealth's CAIR NOx trading budget,

TRA is the total number of CAIR NOx allowances requested by all units requesting allowances under this paragraph.

(3) The Department will review each CAIR NOx allowance allocation request under this subsection and will allocate CAIR NOx allowances for each control period under a request as follows:

(i) The Department will accept an allowance allocation request only if the request meets, or is adjusted by the Department as necessary to meet, the requirements of this section.

(ii) On or after January 1 of the year of allocation, the Department will determine the sum of the CAIR NOx allowances requested.

(4) Up to 1.3% of the Commonwealth's CAIR NOx trading budget is available for allocation in each allocation cycle from 2011-2016 to allocate 2010-2015 allowances for the purpose of offsetting SO2 emissions from units described in paragraph (2). Beginning January 1, 2017, and for each allocation cycle thereafter, the units will no longer be allocated CAIR NOx allowances under paragraph (2). Any allowances remaining after this allocation will be allocated to units under subsection (c) during the next allocation cycle.

(5) Notwithstanding the provisions of paragraphs (2)¿(4), the Department may extend, terminate or otherwise modify the allocation of NOx allowances made available under this subsection for units exempted under section 405(g)(6)(a) of the Clean Air Act after providing notice in the Pennsylvania Bulletin and at least a 30-day public comment period.

(g) The Department will correct any errors in allocations made by the Department and discovered after final allocations are made but before the next allocation cycle, in the subsequent allocation cycle using future allowances that have not yet been allocated.

 # 075 [25 Pa. Code §145.222.]
CAIR NOx Ozone Season allowance allocations.

(a) Provisions not incorporated by reference. The requirements of 40 CFR 96.342 (relating to CAIR NOx Ozone Season allowance allocations) are not incorporated by reference. Instead of 40 CFR 96.342, the requirements in this section apply.

(b) Baseline heat input. Baseline heat input for each CAIR NOx Ozone Season unit will be converted as follows:

(1) A unit's control period heat input and a unit's status as coal-fired or oil-fired for the ozone season portion of a calendar year under this paragraph will be determined in one of the following two ways:

(i) In accordance with 40 CFR Part 75 (relating to continuous emission monitoring), to the extent that the unit was otherwise subject to the requirements of 40 CFR Part 75 for the control period.

(ii) Based on the best available data reported to the Department for the unit, to the extent the unit was not otherwise subject to the requirements of 40 CFR Part 75 for the year.

(2) Except as provided in subparagraphs (iv) and (v), a unit's converted control period heat input for the ozone season portion of a calendar year shall be determined as follows:

(i) The control period gross electrical output of the generators served by the unit multiplied by 7,900 Btu/kWh if the unit is coal-fired for the ozone season control period, and divided by 1,000,000 Btu/mmBtu.

(ii) Not Applicable

(iii) Not Applicable

(iv) Not Applicable

(v) Not Applicable

(vi) Calculations will be based on the best output data available on or before January 31 of the year the allocations are published. If unit level electrical or steam output data are not available from EIA, or submitted by this date by the owner or operator of the CAIR NOx Ozone Season unit, then heat input data for the period multiplied by 0.25 and converted to MWh will be used to determine total output.

(c) Not Applicable

(d) Proration of allowance allocations. The Department will allocate CAIR NOx Ozone Season allowances to each existing CAIR NOx Ozone Season unit and qualifying resource in an amount determined by multiplying the amount of CAIR NOx Ozone Season allowances in the Commonwealth's CAIR NOx Ozone Season trading budget available for allocation under

subsection (c) by the ratio of the baseline heat input of the existing CAIR NOx Ozone Season unit or qualifying resource to the sums of the baseline heat input of existing CAIR NOx Ozone Season units and of the qualifying resources, rounding to the nearest whole allowance as appropriate.
(e) Not Applicable
(f) Not Applicable
(g) The Department will correct any errors in allocations made by the Department and discovered after final allocations are made but before the next allocation cycle, in the subsequent allocation cycle using future allowances that have not yet been allocated.

 # 076 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR NOXsource required to have a title V operating permit and each CAIR NOXunit required to have a title V operating permit at the source shall:
(i) Submit to the permitting authority a complete CAIR permit application under §97.122 in accordance with the deadlines specified in §97.121; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.
(2) The owners and operators of each CAIR NOXsource required to have a title V operating permit and each CAIR NOX unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

 # 077 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(d) Excess emissions requirements. If a CAIR NOXsource emits nitrogen oxides during any control period in excess of the CAIR NOXemissions limitation, then:
(1) The owners and operators of the source and each CAIR NOXunit at the source shall surrender the CAIR NOXallowances required for deduction under §97.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

 # 078 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(f) Liability. (1) Each CAIR NOXsource and each CAIR NOXunit shall meet the requirements of the CAIR NOXAnnual Trading Program.
(2) Any provision of the CAIR NOXAnnual Trading Program that applies to a CAIR NOXsource or the CAIR designated representative of a CAIR NOXsource shall also apply to the owners and operators of such source and of the CAIR NOXunits at the source.
(3) Any provision of the CAIR NOXAnnual Trading Program that applies to a CAIR NOXunit or the CAIR designated representative of a CAIR NOXunit shall also apply to the owners and operators of such unit.
(g) Effect on other authorities. No provision of the CAIR NOXAnnual Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §97.105 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NOXsource or CAIR NOXunit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

 # 079 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR SO2source required to have a title V operating permit and each CAIR SO2unit required to have a title V operating permit at the source shall:
(i) Submit to the permitting authority a complete CAIR permit application under §97.222 in accordance with the deadlines specified in §97.221; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to

review a CAIR permit application and issue or deny a CAIR permit.
(2) The owners and operators of each CAIR SO2source required to have a title V operating permit and each CAIR SO2unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

 # 080 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(d) Excess emissions requirements. If a CAIR SO2source emits sulfur dioxide during any control period in excess of the CAIR SO2emissions limitation, then:
(1) The owners and operators of the source and each CAIR SO2unit at the source shall surrender the CAIR SO2allowances required for deduction under §97.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

 # 081 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(f) Liability. (1) Each CAIR SO2source and each CAIR SO2unit shall meet the requirements of the CAIR SO2Trading Program.
(2) Any provision of the CAIR SO2Trading Program that applies to a CAIR SO2source or the CAIR designated representative of a CAIR SO2source shall also apply to the owners and operators of such source and of the CAIR SO2units at the source.
(3) Any provision of the CAIR SO2Trading Program that applies to a CAIR SO2unit or the CAIR designated representative of a CAIR SO2unit shall also apply to the owners and operators of such unit.
(g) Effect on other authorities. No provision of the CAIR SO2Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §97.205 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR SO2source or CAIR SO2unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

 # 082 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR NOXOzone Season source required to have a title V operating permit and each CAIR NOXOzone Season unit required to have a title V operating permit at the source shall:
(i) Submit to the permitting authority a complete CAIR permit application under §97.322 in accordance with the deadlines specified in §97.321; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.
(2) The owners and operators of each CAIR NOXOzone Season source required to have a title V operating permit and each CAIR NOXOzone Season unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

 # 083 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(d) Excess emissions requirements. If a CAIR NOXOzone Season source emits nitrogen oxides during any control period in excess of the CAIR NOXOzone Season emissions limitation, then:
(1) The owners and operators of the source and each CAIR NOXOzone Season unit at the source shall surrender the CAIR NOXOzone Season allowances required for deduction under §97.354(d)(1) and pay any fine, penalty, or assessment or

comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

 # 084 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

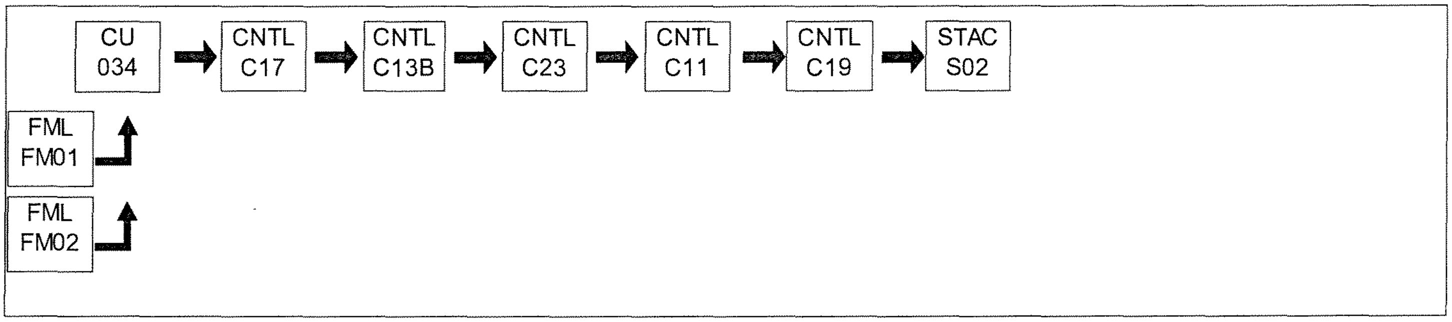
(f) Liability. (1) Each CAIR NOXOzone Season source and each CAIR NOXOzone Season unit shall meet the requirements of the CAIR NOXOzone Season Trading Program.
(2) Any provision of the CAIR NOXOzone Season Trading Program that applies to a CAIR NOXOzone Season source or the CAIR designated representative of a CAIR NOXOzone Season source shall also apply to the owners and operators of such source and of the CAIR NOXOzone Season units at the source.
(3) Any provision of the CAIR NOXOzone Season Trading Program that applies to a CAIR NOXOzone Season unit or the CAIR designated representative of a CAIR NOXOzone Season unit shall also apply to the owners and operators of such unit.
(g) Effect on other authorities. No provision of the CAIR NOXOzone Season Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §97.305 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NOXOzone Season source or CAIR NOXOzone Season unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 034 Source Name: UTILITY BOILER - UNIT 4

Source Capacity/Throughput: 1,790.000 MMBTU/HR



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.11]
Combustion units
No person may permit the emission into the outdoor atmosphere of particulate matter from the exhaust of Source ID 034 in excess of 0.1 pound per million British thermal units (lb/MMBtu) of heat input.

 # 002 [25 Pa. Code §123.22]
Combustion units
(a) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 034 in excess of the rate of 4 lb/MMBtu of heat input over any 1-hour period when firing #2 fuel oil.

(b) No person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO2, from the exhaust of Source ID 034 in excess of the pounds of SO2 per million British thermal units heat input as shown below when firing solid fossil fuels:

Thirty-day running average not to be exceeded at any time: 3.7 lb/MMBtu

Daily average not to be exceeded more than 2 days in any running 30-day period: 4.0 lb/MMBtu

Daily average not to be exceeded at any time: 4.8 lb/MMBtu

 # 003 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 through 129.95]

The nitrogen oxides emissions (NOx, expressed as NO2) from the exhaust of Source ID 034 shall not exceed 0.45 lb/MMBtu of heat input based on a 30 day rolling average.

 # 004 [25 Pa. Code §127.441]
Operating permit terms and conditions.
The ammonia slip resulting from the operation of each SNCR systems (IDs C20, C21, C22 and C23) associated with Source IDs 031, 032, 033 and 034 shall not exceed 5 ppmv corrected to 8% oxygen.

 # 005 [25 Pa. Code §127.531]
Special conditions related to acid rain.
[Additional authority for this permit condition is also derived from 40 CFR Section 70.6(a)(4)]

(a) The permittee shall not emit into the outdoor atmosphere, annual emissions of sulfur dioxide in excess of the number of allowances to emit sulfur dioxide that the permittee or designated representative holds for each affected source.

(b) The permittee shall not emit sulfur dioxide in a manner that would exceed applicable emission rates or standards, including ambient air quality standards.

(c) The permittee shall not use a sulfur dioxide allowance prior to the year for which the allowance is allocated.

(d) A limit will not be placed on the number of sulfur dioxide allowances held for a source. The permittee shall not, however, use allowances as a defense to noncompliance with other applicable requirements.

(e) The permittee shall account for all allowances in accordance with the procedures established in regulations promulgated under Title IV of the Clean Air Act.

 # 006 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(c) Nitrogen oxides emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NOXsource and each CAIR NOXunit at the source shall hold, in the source's compliance account, CAIR NOXallowances available for compliance deductions for the control period under §97.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NOXunits at the source, as determined in accordance with subpart HH of this part.
(2) A CAIR NOXunit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on January 1, 2009.
(3) A CAIR NOXallowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NOXallowance was allocated.
(4) CAIR NOXallowances shall be held in, deducted from, or transferred into or among CAIR NOXAllowance Tracking System accounts in accordance with subparts EE, FF, GG, and II of this part.
(5) A CAIR NOXallowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NOXAnnual Trading Program. No provision of the CAIR NOXAnnual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §97.105 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(6) A CAIR NOXallowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart EE, FF, GG, or II of this part, every allocation, transfer, or deduction of a CAIR NOXallowance to or from a CAIR NOXsource's compliance account is incorporated automatically in any CAIR permit of the source.

 # 007 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(c) Sulfur dioxide emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO2source and each CAIR SO2unit at the source shall hold, in the source's compliance account, a tonnage equivalent in CAIR SO2allowances available for compliance deductions for the control period, as determined in accordance with §97.254(a) and (b), not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO2units at the source, as determined in accordance with subpart HHH of this part.
(2) A CAIR SO2unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2010 or the deadline for meeting the unit(s monitor certification requirements under §97.270(b)(1),(2), or (5) and for each control period thereafter.
(3) A CAIR SO2allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR SO2allowance was allocated.
(4) CAIR SO2allowances shall be held in, deducted from, or transferred into or among CAIR SO2Allowance Tracking System accounts in accordance with subparts FFF, GGG, and III of this part.
(5) A CAIR SO2allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO2Trading Program. No provision of the CAIR SO2Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §97.205 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(6) A CAIR SO2allowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart FFF, GGG, or III of this part, every allocation, transfer, or deduction of a CAIR SO2allowance to or from a CAIR SO2source's compliance account is incorporated automatically in any CAIR permit of the source.

 # 008 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(c) Nitrogen oxides ozone season emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall hold, in the source's compliance account, CAIR NOXOzone Season allowances available for compliance deductions for the control period under §97.354(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NOXOzone Season units at the source, as determined in accordance with subpart HHHH of this part.
(2) A CAIR NOXOzone Season unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §97.370(b)(1), (2), (3), or (7) and for each control period thereafter.
(3) A CAIR NOXOzone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NOXOzone Season allowance was allocated.
(4) CAIR NOXOzone Season allowances shall be held in, deducted from, or transferred into or among CAIR NOXOzone Season Allowance Tracking System accounts in accordance with subparts EEEE, FFFF, GGGG, and IIII of this part.
(5) A CAIR NOXOzone Season allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NOXOzone Season Trading Program. No provision of the CAIR NOXOzone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §97.305 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(6) A CAIR NOXOzone Season allowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart EEEE, FFFF, GGGG, or IIII of this part, every allocation, transfer, or deduction of a CAIR NOXOzone Season allowance to or from a CAIR NOXOzone Season source's compliance account is incorporated automatically in any CAIR permit of the source.

Fuel Restriction(s).

 # 009 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Section 123.22]

The sulfur content of the #2 and lighter fuel oil fired in Source ID 034 shall not exceed 0.5% (by weight).

 # 010 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from RFD condition approved April 8, 2002]

The only binding agents to be used in manufacturing the synthetic fuels used at the Shawville Station shall be soybean oil, Accretion Technologies FTH-100, Nalco 9838, Dow Covol 298 and Dow Covol 298-1 having the compositions identified in the materials submitted with the request for determination dated February 18, 2002 and approved on April 8, 2002. Additionally, the maximum application rate of the soybean oil shall be 1.0% by weight of the soybean oil/coal mixture and the maximum application rate of any of the other four binding agents shall be such that the maximum application rate of the combined non-water constituents contained in the binding agent shall never exceed 1.0% by weight of the binding agent/coal mixture.

II. TESTING REQUIREMENTS.

 # 011 [25 Pa. Code §127.441]
Operating permit terms and conditions.

All continuous emissions monitoring systems shall be tested in accordance with the applicable requirements specified in 25 Pa. Code Chapter 139, the Departments "Continuous Source Monitoring Manual" and 40 CFR Part 75.

 # 012 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable testing requirements specified in 25 Pa. Code Chapter 139 and the Departments "Source Testing Manual."

 # 013 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall conduct testing of the SNCR systems between January 1, 2014 and December 31, 2014 and every five years thereafter. The permittee shall conduct the following testing upon the exhaust of the utility boilers:

(a) Ammonia testing shall be conducted upon the exhausts of Source IDs 031 and 032, respectively, and the common exhaust of Source IDs 033 and 034 using EPA reference method stack testing or an alternative ammonia test method approved by the Department to determine ammonia slip levels and ammonia emissions from each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034.

(b) During the stack testing, the permittee shall measure and, record the gross megawatt load, NOx emissions and SNCR ammonia slip levels for each of the SNCR systems servicing Source IDs 031 and 032 respectively, and the set of SNCR systems servicing Source IDs 033 and 034, and such information shall be provided in the stack test report submitted to the Department.

 # 014 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.6(b)(3)]

(a) Within 120 day of the issuance date of this permit, the permittee shall perform stack testing on the four utility boilers (Source IDs 031, 032, 033 and 034) to demonstrate compliance with the particulate matter emission limitation contained in this operating permit and obtain data to verify the validity of the Linear Regression equations and establish new Linear Regression equations (as approved by the Department) per the procedures in the 2007 CAM plan if the data warrants the establishment of new Linear Regression equations.

(b) Subsequent testing shall be performed on an approximate 2-year period, but in each case, no less than 20 months and no greater than 26 months following the date of the previous test.

(c) Stack testing shall be performed in accordance with the applicable provisions of 25 Pa. Code Chapter 139 (relating to sampling and testing) using test methods and procedures approved by the Department. Testing must be performed while the sources are operating under maximum normal operating conditions.

III. MONITORING REQUIREMENTS.

 # 015 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 123.25, 123.46, 123.51, 40 CFR Part 75]

The permittee shall install, calibrate, maintain and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxide emissions, carbon dioxide concentration (%CO2) and volumetric flow in accordance with all applicable requirements specified in, or established pursuant to: 25 Pa. Code Chapters 123 and 139, the Department's "Continuous Source Monitoring Manual" and 40 CFR Part 75.

 # 016 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable monitoring requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 017 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall install and maintain instrumentation to monitor and record the ammonia injection rate of the SNCR systems associated with Source IDs 031, 032, 033, and 034 on a continuous basis. Additionally, the permittee shall continuously monitor and record the gross megawatt load and NOx emissions associated with the boilers.

These records shall be retained for a minimum of five years and shall be presented to the Department upon request.

 # 018 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Authority for this condition is also derived from 40 CFR Part 64, relating to Compliance Assurance Monitoring (CAM)]

Compliance Assurance Monitoring (CAM) Protocol
(A) The purpose of this protocol is to outline procedures for the development, verification, operation, and ongoing maintenance of a continuous monitoring approach sufficient to reasonably assure that Source IDs 031, 032, 033, and 034 operate in compliance with the 0.1 lb/MMBtu particulate matter emission limitation.

(B) Monitoring designed and operated in accordance with this protocol satisfies the requirements of the CAM rule's monitoring design criteria in 40 CFR Section 64.3(a) and (b) pursuant to 40 CFR Section 64.3(d)(2).

I. CAM Indicators - Predicted Particulate Matter (PM) and Opacity of Exhaust
Measurement Approach - Predicted PM, in units of lb/MMBtu, using the % opacity measured by the COMS; the %CO2(w) measured by the CO2 CEMS; Unit's 3 and 4 gross megawatt load (MW) measured by the continuous gross megawatt load meter, data acquisition and handling system and Linear Regression equations (as approved by the Department).

II. CAM Indicator Parameters and Excursion
(A) As identified below, the predicted PM (1-hour average) is used as the CAM indicator paramater to comply with the requirements specified in 40 CFR Section 64.3(d)(3)(ii).

(B) The permittee shall assure the measured % opacity, %CO2(w), gross megawatt load and predicted PM are recorded in accordance to the requirements specified in 40 CFR Section 64.3(b)(4)(ii)

(C) The predicted PM for Units 1 and 2 shall be determined from the CAM indicators, including the predicted PM concentration, using the following equation:

lb/MMBtu = Y * (1 / 7000) * Fc * (100 / %CO2(w)) where,

Y = the predicted PM concentration (gr/scf) calculated by using the most recently approved Linear Regression equations
Fc = carbon-based F-factor
%CO2(w) = the %CO2 measured in accordance with item (d)(2) of this condiiton

(D) The predicted PM for Units 3 and 4 shall be determined from the CAM indicators, including the predicted PM concentration and emission apportionment factor (EAF) using the following equation:

lb/MMBtu = Y * (1 / 7000) * Fc * (100 / %CO2(w)) * EAF where,

Y = the predicted PM concentration (gr/scf) calculated by using the most recently approved Linear Regression equations,
Fc = carbon-based F-factor,
%CO2(w) = the %CO2 measured in accordance with item (d)(2) of this condiiton
EAF = each unit's average hourly gross megawatt load measured in accordance with item (d)(3) of this condition divided by the sum of hourly gross megawatt loads for Units 3 and 4.

(E) Each instance where the predicted PM rate (1-hour block average) exceeds 0.09 lb/MMBtu is defined to be an excursion.

(F) When an excursion occurs (the predicted PM rate, 1-hour block average exceeds 0.09 lb/MMBtu), the permittee shall initiate and comply with the requirements of 40 CFR Section 64.7(d).

III. Performance Criteria
(a) Data Representativeness

(1) The predicted PM using the % opacity measured by the COMS is proportional to the amount of filterable PM in the exhaust. Opacity shall be correlated to the PM concentration in accordance with the Investigative Program. The Investigative Program shall use the procedures specified in the 2007 CAM plan and the data obtained from the most recently approved stack tests for PM.

(b) Verification of Operational Status
(1) The operation of the COMS shall be verified by the presence of a valid opacity signal on the COMS readout; the results of the performance evaluations conducted as per 25 Pa. Code Chapter 139; and the presence of a valid result of the predicted PM rate (1-hour block average).

(c) QA/QC Practices
(1) The operation of the COMS and CEMS shall meet the requirements of 25 Pa. Code Chapter 139.

(2) See the condition under II. Testing Requirements for additional QA/QC practice requirements.

(d) Data Collection Procedures & Averaging Periods
(1) An electronic data handling and acquisition system (DAHS) shall collect data points representative of the opacity in the exhaust from the COMS approximately every 10 seconds. These % opacity readings shall be reduced to 1-minute averages and then to 1-hour averages.

(2) An electronic DAHS shall collect data points from the CO2 CEMS approximately every second. These %CO2(w) readings shall be reduced to 1-minute averages and then to 1-hour averages. Monitor response time shall be less than 15 minutes.

(3) An electronic DAHS shall collect data points from the continuous gross megawatt load meter installed on Unit 3 and 4 approximately every 15 minutes. The hourly average gross megawatt load meter for Unit 3 and 4 shall be calculated from the 15-minute data. Monitor response time shall be less than 15 minutes.

(4) An electronic DAHS shall calculate a minimum of 4 equally-spaced PM emission concentrations over a 1-hour period pursuant to the requirements of 40 CFR §64.3(b)(4)(ii). These PM emission concentrations will be calculated using the following equations. The following Linear Regression equations were obtained from the June 2005 testing program.

Y = (6.79E-05) * X^(2) for Unit 1

Y = (1.26E-05) * X^(2.5) for Unit 2

Y = (1.14E-05) * X^(2.3) for Unit 3 and 4 Common Stack,

Where Y = PM concentration (gr/scf)
X = Opacity (%)

(5) An electronic DAHS shall calculate a minimum of 4 equally-spaced PM rates, in units of lb/MMBtu over a 1-hour period pursuant to the requirements of 40 CFR §64.3(b)(4)(ii). These PM rates shall be calculated using the equations listed in this condition under II. (C) for Units 1 and 2 and II. (D) for Units 3 and 4. The 4 equally-spaced PM rates shall be reduced to 1-hour averages.

 # 019 [25 Pa. Code §145.213.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.170--96.175.

(a) The owner or operator of the CAIR NOx unit shall install, calibrate, maintain and operate a wattmeter, measure gross electrical output in megawatt-hours on a continuous basis and record the output of the wattmeter. If a generator is served by two or more units, the information to determine the heat input of each unit for that control period shall also be recorded, so as to allow each unit's share of the gross electrical output to be determined. If heat input data are used, the owner or operator shall comply with the applicable provisions of 40 CFR Part 75 (relating to continuous emission monitoring).
(b) Not Applicable

 # 020 [25 Pa. Code §145.223.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.370--96.375.

(a) The owner or operator of the CAIR NOx Ozone Season unit shall install, calibrate, maintain and operate a wattmeter, measure gross electrical output in megawatt-hours on a continuous basis and record the output of the wattmeter. If a generator is served by two or more units, the information to determine the heat input of each unit for that control period shall also be recorded, so as to allow each unit's share of the gross electrical output to be determined. If heat input data are used, the owner or operator shall comply with the applicable provisions of 40 CFR Part 75 (relating to continuous emission monitoring).
(b) Not Applicable

 # 021 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.10]
Subpart B--Monitoring Provisions
General operating requirements.

The requirements in 40 CFR Section 75.10 apply.

 # 022 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.11]
Subpart B--Monitoring Provisions
Specific provisions for monitoring SO2 emissions (SO2 and flow monitors).

The requirements in 40 CFR 75.11 apply.

 # 023 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.12]
Subpart B--Monitoring Provisions
Specific provisions for monitoring NOx emissions (NOx and diluent gas monitors).

The requirements in 40 CFR 75.12(a) and (b) apply.

 # 024 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.13]
Subpart B--Monitoring Provisions
Specific provisions for monitoring CO2 emissions.

The requirements in 40 CFR 75.13(a) apply.

 # 025 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.14]
Subpart B--Monitoring Provisions
Specific provisions for monitoring opacity.

The requirements in 40 CFR 75.14(a) and (b) apply.

 # 026 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.2]
Subpart A--General
Applicability.

The requirements in 40 CFR 75.2 apply.

 # 027 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.20]
Subpart C--Operation and Maintenance Requirements
Certification and recertification procedures.

The requirements of 40 CFR 75.20 apply except for 40 CFR 75.20(e), (f) and (g).

 # 028 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.21]
Subpart C--Operation and Maintenance Requirements
Quality assurance and quality control requirements.

The requirements in 40 CFR 75.21(a)(1), (a)(2) and (a)(3) apply.

 # 029 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.22]
Subpart C--Operation and Maintenance Requirements
Reference test methods.

The requirements in 40 CFR 75.22 apply.

 # 030 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.24]
Subpart C--Operation and Maintenance Requirements
Out-of-control periods.

The requirements in 40 CFR 75.24 apply.

 # 031 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.30]
Subpart D--Missing Data Substitution Procedures
General provisions.

The requirements in 40 CFR 75.30 apply.

 # 032 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.4]
Subpart A--General
Compliance dates.

The requirements in 40 CFR 75.4(a)(3) apply.

 # 033 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.53]
Subpart F--Recordkeeping Requirements
Monitoring plan.

The requirements in 40 CFR 75.53 apply.

 # 034 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.60]
Subpart G--Reporting Requirements
General provisions.

The requirements in 40 CFR 75.60 apply.

 # 035 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.62]
Subpart G--Reporting Requirements
Monitoring plan.

The requirements of 40 CFR 75.62 apply.

 # 036 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.63]
Subpart G--Reporting Requirements
Initial certification or recertification application.

The requirements in 40 CFR 75.63 apply.

 # 037 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.64]
Subpart G--Reporting Requirements
Quarterly reports.

The requirements in 40 CFR 75.64 apply.

 # 038 [40 CFR Part 75 Continuous Emission Monitoring §40 CFR 75.65]
Subpart G--Reporting Requirements
Opacity reports.

The requirements in 40 CFR 75.65 apply.

 # 039 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR NOXsource and each CAIR NOXunit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HH of this part.
(2) The emissions measurements recorded and reported in accordance with subpart HH of this part shall be used to determine compliance by each CAIR NOXsource with the CAIR NOXemissions limitation under paragraph (c) of this section.

 # 040 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]

Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR SO2source and each CAIR SO2unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHH of this part.
(2) The emissions measurements recorded and reported in accordance with subpart HHH of this part shall be used to determine compliance by each CAIR SO2source with the CAIR SO2emissions limitation under paragraph (c) of this section.

 # 041 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of this part.
(2) The emissions measurements recorded and reported in accordance with subpart HHHH of this part shall be used to determine compliance by each CAIR NOXOzone Season source with the CAIR NOXOzone Season emissions limitation under paragraph (c) of this section.

IV. RECORDKEEPING REQUIREMENTS.

 # 042 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable recordkeeping requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 043 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

(a) The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95.

(b) The permittee shall keep records, including data which clearly demonstrates that the NOX emission limits for Source ID 034 are met.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

 # 044 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall keep records of the data and calculations used to verify compliance with the particulate matter and sulfur oxides (SOx) emissions limitations for Source ID 034.

(b) The permittee shall keep records of the tests conducted or certification reports used to verify the sulfur content (percent by weight) of the fuel oil.

These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

 # 045 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall keep records of the calculations, including ammonia emissions test reports, used to determine compliance with the SNCR ammonia slip emissions limitations for Source IDs 031, 032, 033 and 034. These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

 # 046 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall record all excursions and corrective actions taken in response to an excursion and the time elapsed until the corrective actions have been taken.

(b) The permittee shall keep records of all monitoring downtime incidents associated with the COMS and CO2 CEMS associated with Source IDs 031 through 034. The permittee shall also record the dates, times and durations, possible causes, and corrective actions taken for the incidents.

(c) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 047 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Compliance with the requirements in item (b) of this condition will assure compliance with the requirements of 40 CFR Section 64.7(c)]

[Additional authority items (a)-(b) of this condition is also derived from 40 CFR §64.6 & §64.3]

[Additional authority for permit conditions (c) is also derived from 40 CFR §64.9]

[Additional authority for permit condition (f) is also derived from 40 CFR §70.6(a)(3)(ii)(b)]

(a) The permittee shall use the following devices to monitor and record CAM indicators:
(i) The certified COMS that measure % opacity readings at a location downstream of each of the electrostatic precipitators (IDs C01, C04, C08, C09, C11, C12, C18, and C19).
(ii) The certified CEMS that measure the %CO2(w) at each of the stacks (ID S01 and S02)
(iii) Gross load meter to measure Unit's 3 and 4 gross megawatt load
(iv) Data Acquistion and handling systems (DAHS) to record all CAM indicators and calculate the predicted hourly PM rate, in units of lb/MMBtu.

(b) The permittee shall use the devices above to conduct monitoring and record the CAM indicators in accordance with the requirements of 40 CFR 64.3(b)(4)(ii).

(c) The permittee shall maintain supporting documentation to verify compliance with the requirements of 40 CFR Sections 64.9(a)(2)(i) and 64.7(b).

(d) The permittee shall maintain records of the operation of the devices above in order to report the information required in in 40 CFR Section 64.9(a)(2)(ii).

(e) The permittee shall maintain supporting information that verify that each response to an excursion meets the requirements of 40 CFR Section 64.7(d)

(f) The permittee shall keep all records for a period of five (5) years and shall make the records available to the Department upon request.

 # 048 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9]

(a) The permittee shall keep records of all inspections, repairs, and maintenance performed on the devices used for Source IDs 031 through 034 CAM monitoring.

(b) The permittee shall record all excursions and corrective actions taken in response to an excursion and the time elapsed until the corrective actions have been taken.

(c) The permittee shall keep records of all monitoring downtime incidents associated with the devices used for Source IDs 031 through 034 CAM monitoring. The permittee shall also record the dates, times and durations, possible causes, and corrective actions taken for the downtime incidents.

(d) These records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

 # 049 [25 Pa. Code §145.213.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.170--96.175.

(d) The owner or operator of a CAIR NOx unit shall maintain onsite the monitoring plan detailing the monitoring system and maintenance of the monitoring system, including quality assurance activities. The owner or operator of a CAIR NOx unit shall retain the monitoring plan for at least 5 years from the date that it is replaced by a new or revised monitoring plan. The owner or operator of a CAIR NOx Ozone Season unit shall provide the Department with a written copy of updates to the submitted monitoring plan, including a copy of the revised monitoring plan within 3 calendar months of making updates to the plan.
(e) The owner or operator of a CAIR NOx unit shall retain records for at least 5 years from the date the record is created or the data collected as required by subsections (a) and (b), and the reports submitted to the Department and the EPA in accordance with subsections (c) and (d).

 # 050 [25 Pa. Code §145.223.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.370--96.375.

(d) The owner or operator of a CAIR NOx Ozone Season unit shall maintain onsite the monitoring plan detailing the monitoring system and maintenance of the monitoring system, including quality assurance activities. The owner or operator of a CAIR NOx Ozone Season unit shall retain the monitoring plan for at least 5 years from the date that it is replaced by a new or revised monitoring plan. The owner or operator of a CAIR NOx Ozone Season unit shall provide the Department with a written copy of updates to the submitted monitoring plan, including a copy of the revised monitoring plan within 3 calendar months of making updates to the plan.
(e) The owner or operator of a CAIR NOx Ozone Season unit shall retain records for at least 5 years from the date the record is created or the data collected as required by subsections (a) and (b), and the reports submitted to the Department and the EPA in accordance with subsections (c) and (d).

 # 051 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR NOXsource and each CAIR NOXunit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §97.113 for the CAIR designated representative for the source and each CAIR NOXunit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.113 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subpart HH of this part, provided that to the extent that subpart HH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the

CAIR NOXAnnual Trading Program.
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NOXAnnual Trading Program or to demonstrate compliance with the requirements of the CAIR NOXAnnual Trading Program.

 # 052 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR SO2source and each CAIR SO2unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §97.213 for the CAIR designated representative for the source and each CAIR SO2unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.213 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subpart HHH of this part, provided that to the extent that subpart HHH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR SO2Trading Program.
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR SO2Trading Program or to demonstrate compliance with the requirements of the CAIR SO2Trading Program.

 # 053 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §97.313 for the CAIR designated representative for the source and each CAIR NOXOzone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.313 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subpart HHHH of this part, provided that to the extent that subpart HHHH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NOXOzone Season Trading Program.
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NOXOzone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NOXOzone Season Trading Program.

V. REPORTING REQUIREMENTS.

 # 054 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall comply with all applicable reporting requirements specified in 25 Pa. Code Chapter 139 and the Departments "Continuous Source Monitoring Manual".

 # 055 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Additional authority for this permit condition is derived from 40 CFR Section 64.9 and Section 70.6(a)(3)(iii)(A)]

(a) The permittee shall submit reports to the Department on a semi-annual basis that include the records of all excursions and corrective actions taken, the dates, times, durations, and possible causes.

(b) The permittee shall submit reports to the Department on a semi-annual basis that include all monitoring downtime incidents, their dates, times and durations, possible causes, and corrective actions taken.

(c) The semi-annual reports shall be submitted to the Department no later than March 1 (for July 1 through December 31 of the previous year) and September 1 (for January 1 through June 30 of the current year).

 # 056 [25 Pa. Code §145.213.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.170--96.175.

(c) The designated representative of the units associated with Source IDs 031 through 034 shall submit to the Department an annual report showing monthly gross electrical output and monthly useful thermal energy from the unit. The report is due by January 31 for the preceding calendar year.

 # 057 [25 Pa. Code §145.223.]
Supplemental monitoring, recordkeeping and reporting requirements for gross electrical output and useful thermal energy for units subject to 40 CFR 96.370--96.375.

(c) The designated representative of the units associated with Source IDs 031 through 034 shall submit to the Department an annual report showing monthly gross electrical output and monthly useful thermal energy from the unit. The report is due by January 31 for the preceding calendar year.

 # 058 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(b)(2) The CAIR designated representative of a CAIR NOXsource and each CAIR NOXunit at the source shall submit the reports required under the CAIR NOXAnnual Trading Program, including those under subpart HH of this part.

 # 059 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(e)(2) The CAIR designated representative of a CAIR SO2source and each CAIR SO2unit at the source shall submit the reports required under the CAIR SO2Trading Program, including those under subpart HHH of this part.

 # 060 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(e)(2) The CAIR designated representative of a CAIR NOXOzone Season source and each CAIR NOXOzone Season unit at the source shall submit the reports required under the CAIR NOXOzone Season Trading Program, including those under subpart HHHH of this part.

VI. WORK PRACTICE REQUIREMENTS.

 # 061 [25 Pa. Code §127.441]
Operating permit terms and conditions.

No reclaimed or waste oil or oil that contains any waste material shall be used as fuel in the lighter associated with the low NOX burners of Source ID 034.

 # 062 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 129.91]

The permittee shall maintain and operate Source ID 034 in accordance with the manufacturers specifications. This requirement shall be considered as VOC RACT for Source ID 034.

 # 063 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The SNCR systems (Control Device IDs C20, C21, C22, and C23) shall be operated in accordance with the manufacturer specifications and good air pollution control practices.

 # 064 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall comply with the requirements specified in 40 CFR Section 64.7(b) and (d), relating to Proper maintenance and Response to excursions, respectively.

VII. ADDITIONAL REQUIREMENTS.

 # 065 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Sources ID 033 and 034 (Unit 3 and 4) may be used for the incineration/evaporation of liquid wastes resulting from the chemical cleaning of boiler tubes with non-hazardous (HAP) and non-VOC containing liquid cleaning solutions.

 # 066 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source ID 034 is a 1960 vintage, Combustion Engineering, tangential fired, balanced draft, divided furnace, with a combined circulation, radiant, reheat boiler with a rated heat input capacity of 1,790 MMBtu/hr. The boiler is fueled with pulverized bituminous coal/synfuel or #2 oil. The air contaminant emissions from the subject boiler shall be controlled by low NOX burners {LNCFSIII} (Control Device ID C17), overfire air (Control Device ID C13B) and a two stage Research Cottrell & Buell electrostatic precipitator (Control Device IDs C11 and C19).

The nitrogen oxides emissions from Source ID 034 may further be controlled by an Energy System Associates selective non-catalytic reduction system (Control Device ID C23).

 # 067 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Control Device IDs C20 and C21 associated with Source IDs 031 and 032 are considered SNCR system #1, which also consists of a storage tank and a recirculation pump. Control Device IDs C22 and C23 associated with Source IDs 033 & 034 are considered SNCR system #2, which also consists of a storage tank and a recirculation pump.

 # 068 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 64.8]

(a) The permittee shall develop and implement a Quality Improvement Plan (QIP) as expeditiously as practicable if any of the following occur:
(1) Six (6) excursions occur in a six (6) month reporting period.
(2) The Department determines after review of all reported information that the permittee has not responded acceptably to an excursion.

(b) The QIP should be developed within 60 days and the permittee shall provide a copy of the QIP to the Department. Furthermore, the permittee shall notify the Department if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(c) The permittee shall record actions taken to implement a QIP during a reporting period and all related actions including, but not limited to, inspections, repairs, and maintenance performed on the COMS, CO2 CEMS, gross megawatt load meter and DAHS.

(d) In accordance with 40 CFR Section 64.8, the QIP shall include procedures for evaluating the control performance

problems. Based on the results of the evaluation procedures, the permittee shall modify the QIP and provide the Department with a copy, to include procedures for conducting more frequent, or improved, monitoring in conjunction with one or more of the following:
(1) Improved preventive maintenance practices,
(2) Process operation changes,
(3) Appropriate improvements to the control methods,
(4) Other steps appropriate to correct performance.

(e) Following implementation of a QIP, the Department will require reasonable revisions to the QIP if the plan has failed to either:
(1) Address the cause of the performance problems of the COMS, CO2 CEMS, gross megawatt load meter and/or DAHS.
(2) Provide adequate procedures for correcting the performance problems of the device(s) in an expeditious manner and according to good air pollution control practices.

(f) Implementation of a QIP shall not excuse the permittee from compliance with any existing emission limitation or standard or any existing monitoring, testing, reporting or recordkeeping requirements that may apply under any federal, state, or local laws or any other applicable requirements under the Clean Air Act.

 # 069 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source IDs 031 through 034 are subject to the CAM requirements of 40 CFR Part 64. The permittee shall comply with all applicable requirements of 40 CFR Sections 64.1 through 64.10.

 # 070 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source IDs 031 through 034 are defined to be affected sources in the National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (77 FR 9304). As the owner and operator of Source IDs 031 and 034, the permittee shall comply with all applicable requirements codified in 40 CFR Part 63 Subpart UUUUU (40 CFR §§ 63.9980 through 63.10042, including Tables and Appendices).

 # 071 [25 Pa. Code §127.531]
Special conditions related to acid rain.

The permittee shall comply with all applicable requirements and procedures established in regulations promulgated under Title IV of the Clean Air Act, including all applicable provisions from the following:

40 CFR Part 72	Permit Regulation
40 CFR Part 73	Sulfur Dioxide Allowance System
40 CFR Part 75	Continuous Emission Monitoring
40 CFR Part 76	Nitrogen Oxides Emission Reduction Program
40 CFR Part 77	Excess Emissions

Attached to Title V Operating Permit 17-00001 is the Phase II Title IV Operating Permit 17-00001 (Acid Rain Permit) in its entirety. The Acid Rain Permit was renewed on May 29, 2009 and is effective through December 31, 2012. Certain requirements from the Acid Rain permit have been reiterated in the body of the Title V operating permit for emphasis. The entire Acid Rain Permit is incorporated into the Title V operating permit by inclusion.

 # 072 [25 Pa. Code §145.204.]
Incorporation of Federal regulations by reference.

(a) Except as otherwise specified in this subchapter and herein, the provisions of the CAIR NOx Annual Trading Program, found in 40 CFR Part 96 (relating to NOx budget trading program and CAIR NOx and SO2 trading programs for State implementation plans), including all appendices, future amendments and supplements thereto, are incorporated by reference.
(b) Except as otherwise specified in this subchapter and herein, the provisions of the CAIR SO2 Trading Program, found in 40 CFR Part 96, including all appendices, future amendments and supplements thereto, are incorporated by reference.
(c) Except as otherwise specified in this subchapter and herein, the provisions of the CAIR NOx Ozone Season Trading Program, found in 40 CFR Part 96, including all appendices, future amendments and supplements thereto, are

incorporated by reference.

(d) In the event of a conflict between Federal regulatory provisions incorporated by reference in this subchapter and Pennsylvania regulatory provisions, the provision expressly set out in this subchapter shall be followed unless the Federal provision is more stringent. Federal regulations that are cited in this subchapter or that are cross-referenced in the Federal regulations incorporated by reference include any Pennsylvania modifications made to those Federal regulations.

 # 073 [25 Pa. Code §145.205.]
Emission reduction credit provisions.

The following conditions shall be satisfied in order for the Department to issue a permit or plan approval to the owner or operator of a unit not subject to this subchapter that is relying on emission reduction credits (ERCs) or creditable emission reductions in an applicability determination under Chapter 127, Subchapter E (relating to new source review), or is seeking to enter into an emissions trade authorized under Chapter 127 (relating to construction, modification, reactivation and operation of sources), if the ERCs or creditable emission reductions were, or will be, generated by a unit subject to this subchapter.

(1) Prior to issuing the permit or plan approval, the Department will permanently reduce the Commonwealth's CAIR NOx trading budget or CAIR NOx Ozone Season trading budget, or both, as applicable, beginning with the sixth control period following the date the plan approval or permit to commence operations or increase emissions is issued. The Department will permanently reduce the applicable CAIR NOx budgets by an amount of allowances equal to the ERCs or creditable emission reductions relied upon in the applicability determination for the non-CAIR unit subject to Chapter 127, Subchapter E or in the amount equal to the emissions trade authorized under Chapter 127, as if these emissions had already been emitted.

(2) The permit or plan approval must prohibit the owner or operator from commencing operation or increasing emissions until the owner or operator of the CAIR unit generating the ERC or creditable emission reduction surrenders to the Department an amount of allowances equal to the ERCs or emission reduction credits relied upon in the applicability determination for the non-CAIR unit under Chapter 127, Subchapter E or the amount equal to the ERC trade authorized under Chapter 127, for each of the five consecutive control periods following the date the non-CAIR unit commences operation or increases emissions. The allowances surrendered must be of present or past vintage years.

 # 074 [25 Pa. Code §145.212.]
CAIR NOx allowance allocations.

(a) Provisions not incorporated by reference. The requirements of 40 CFR 96.142 (relating to CAIR NOx allowance allocations) are not incorporated by reference. Instead of 40 CFR 96.142, the requirements set forth in this section apply.

(b) Baseline heat input. Baseline heat input for each CAIR NOx unit will be converted as follows:

(1) A unit's control period heat input and a unit's status as coal-fired or oil-fired for a calendar year under this paragraph will be determined in one of the following two ways:

(i) In accordance with 40 CFR Part 75 (relating to continuous emission monitoring), to the extent that the unit was otherwise subject to 40 CFR Part 75 for the year.

(ii) Based on the best available data reported to the Department for the unit, to the extent the unit was not otherwise subject to the requirements of 40 CFR Part 75 for the year.

(2) Except as provided in subparagraphs (iv) and (v), a unit's converted control period heat input for a calendar year shall be determined as follows:

(i) The control period gross electrical output of the generators served by the unit multiplied by 7,900 Btu/kWh if the unit is coal-fired for the year, and divided by 1,000,000 Btu/mmBtu.

(ii) The control period gross electrical output of the generators served by the unit multiplied by 6,675 Btu/kWh if the unit is not coal-fired for the year, and divided by 1,000,000 Btu/mmBtu.

(iii) Not Applicable

(iv) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating or cooling purposes through the sequential use of energy, the total heat energy (in Btus) of the steam produced by the boiler during the annual control period, divided by 0.8 and by 1,000,000 Btu/mmBtu.

(v) Not Applicable

(vi) Calculations will be based on the best output data available on or before January 31 of the year the allocations are published. If unit level electrical or steam output data are not available from EIA, or submitted by this date by the owner or operator of the CAIR NOx unit, then heat input data for the period multiplied by 0.25 and converted to MWh will be used to determine total output.

(c) Existing unit, new unit and subsection (f)(1) qualifying resource allocation baseline. For each control period beginning with January 1, 2010, and each year thereafter, the Department will allocate to qualifying resources and CAIR NOx units, including CAIR NOx units issued allowances under subsection (e), a total amount of CAIR NOx allowances equal to the number of CAIR NOx allowances remaining in the Commonwealth's CAIR NOx trading budget under 40 CFR 96.140 (relating to State trading budgets) for those control periods using summed baseline heat input data as determined under subsections (b) and (f)(1) from a baseline year that is 6 calendar years before the control period.

(d) Proration of allowance allocations. The Department will allocate CAIR NOx allowances to each existing CAIR NOx unit and qualifying resource in an amount determined by multiplying the amount of CAIR NOx allowances in the Commonwealth's CAIR NOx trading budget available for allocation under subsection (c) by the ratio of the baseline heat input of the existing CAIR NOx unit or qualifying resource to the sum of the baseline heat input of existing CAIR NOx units and of the qualifying resources, rounding to the nearest whole allowance as appropriate.

(e) Allocations to new CAIR NOx units. By March 31, 2011, and March 31 each year thereafter, the Department will allocate CAIR NOx allowances under § 145.211(c) (relating to timing requirements for CAIR NOx allowance allocations) to CAIR NOx units equal to the previous year's emissions at each unit, unless the unit has been issued allowances of the previous year's vintage in a regular allocation under § 145.211(b). The Department will allocate CAIR NOx allowances under this subsection of a vintage year that is 5 years later than the year in which the emissions were generated. The number of CAIR NOx allowances allocated may not exceed the actual emission of the year preceding the year in which the Department makes the allocation. The allocation of these allowances to the new unit will not reduce the number of allowances the unit is entitled to receive under another provision of this subchapter.

(f) Allocations to qualifying resources and units exempted by section 405(g)(6)(a) of the Clean Air Act. For each control period beginning with 2010 and thereafter, the Department will allocate CAIR NOx allowances to qualifying resources under paragraph (1) in this Commonwealth that are not also allocated CAIR NOx allowances under another provision of this subchapter and to existing units under paragraph (2) that were exempted at any time under section 405(g)(6)(a) of the Clean Air Act (42 U.S.C.A. § 7651d(g)(6)(A)), regarding phase II SO2 requirements, and that commenced operation prior to January 1, 2000, but did not receive an allocation of SO2 allowances under the EPA's Acid Rain Program, as follows:

(1) The Department will allocate CAIR NOx allowances to a renewable energy qualifying resource or demand side management energy efficiency qualifying resource in accordance with subsections (c) and (d) upon receipt by the Department of an application, in writing, on or before June 30 of the year following the control period, except for vintage year 2011 and 2012 NOx allowance allocations whose application deadline will be prescribed by the Department, meeting the requirements of this paragraph. The number of allowances allocated to the qualifying resource will be determined by converting the certified quantity of electric energy production, useful thermal energy, and energy equivalent value of the measures approved under the Pennsylvania Alternative Energy Portfolio Standard to equivalent thermal energy. Equivalent thermal energy is a unit's baseline heat input for allocation purposes. The conversion rate for converting electrical energy to equivalent thermal energy is 3,413 Btu/kWh. To receive allowances under this subsection, the qualifying resource must have commenced operation after January 1, 2005, must be located in this Commonwealth and may not be a CAIR NOx unit. The following procedures apply:

(i) The owner of a qualifying renewable energy resource shall appoint a CAIR-authorized account representative and file a certificate of representation with the EPA and the Department.

(ii) The Department will transfer the allowances into an account designated by the owner's CAIR-authorized account representative of the qualifying resource, or into an account designated by an aggregator approved by the Pennsylvania Public Utility Commission or its designee.

(iii) The applicant shall provide the Department with the corresponding renewable energy certificate serial numbers.

(iv) At least one whole allowance must be generated per owner, operator or aggregator for an allowance to be issued.

(2) The Department will allocate CAIR NOx allowances to the owner or operator of a CAIR SO2 unit that commenced operation prior to January 1, 2000, that has not received an SO2 allocation for that compliance period, as follows:

(i) By January 31, 2011, and each year thereafter, the owner or operator of a unit may apply, in writing, to the Department under this subsection to receive extra CAIR NOx allowances.

(ii) The owner or operator may request under this subparagraph one CAIR NOx allowance for every 8 tons of SO2 emitted from a qualifying unit during the preceding control period. An owner or operator of a unit covered under this subparagraph that has opted into the Acid Rain Program may request one CAIR NOx allowance for every 8 tons of SO2 emissions that have not been covered by the SO2 allowances received as a result of opting into the Acid Rain Program.

(iii) If the original CAIR NOx allowance allocation for the unit for the control period exceeded the unit¿s actual emissions of NOx for the control period, the owner or operator shall also deduct the excess CAIR NOx allowances from the unit's request under subparagraph (ii). This amount is the unit's adjusted allocation and will be allocated unless the proration described in subparagraph (iv) applies.

(iv) The Department will make any necessary corrections and then sum the requests. If the total number of NOx allowances requested by all qualified units under this paragraph, as adjusted by subparagraph (iii), is less than 1.3% of the Commonwealth's CAIR NOx Trading Budget, the Department will allocate the corrected amounts. If the total number of NOx allowances requested by all qualified units under this paragraph exceeds 1.3% of the Commonwealth's CAIR NOx Trading Budget, the Department will prorate the allocations based upon the following equation:

AA = [EA X (0.013 X BNA)] / TRA

where,

AA is the unit's prorated allocation,

EA is the adjusted allocation the unit may request under subparagraph (iii),

BNA is the total number of CAIR NOx allowances in the Commonwealth's CAIR NOx trading budget,

TRA is the total number of CAIR NOx allowances requested by all units requesting allowances under this paragraph.

(3) The Department will review each CAIR NOx allowance allocation request under this subsection and will allocate CAIR NOx allowances for each control period under a request as follows:

(i) The Department will accept an allowance allocation request only if the request meets, or is adjusted by the Department as necessary to meet, the requirements of this section.

(ii) On or after January 1 of the year of allocation, the Department will determine the sum of the CAIR NOx allowances requested.

(4) Up to 1.3% of the Commonwealth's CAIR NOx trading budget is available for allocation in each allocation cycle from 2011-2016 to allocate 2010-2015 allowances for the purpose of offsetting SO2 emissions from units described in paragraph (2). Beginning January 1, 2017, and for each allocation cycle thereafter, the units will no longer be allocated CAIR NOx allowances under paragraph (2). Any allowances remaining after this allocation will be allocated to units under subsection (c) during the next allocation cycle.

(5) Notwithstanding the provisions of paragraphs (2)¿(4), the Department may extend, terminate or otherwise modify the allocation of NOx allowances made available under this subsection for units exempted under section 405(g)(6)(a) of the Clean Air Act after providing notice in the Pennsylvania Bulletin and at least a 30-day public comment period.

(g) The Department will correct any errors in allocations made by the Department and discovered after final allocations are made but before the next allocation cycle, in the subsequent allocation cycle using future allowances that have not yet been allocated.

 # 075 [25 Pa. Code §145.222.]
CAIR NOx Ozone Season allowance allocations.

(a) Provisions not incorporated by reference. The requirements of 40 CFR 96.342 (relating to CAIR NOx Ozone Season allowance allocations) are not incorporated by reference. Instead of 40 CFR 96.342, the requirements in this section apply.

(b) Baseline heat input. Baseline heat input for each CAIR NOx Ozone Season unit will be converted as follows:

(1) A unit's control period heat input and a unit's status as coal-fired or oil-fired for the ozone season portion of a calendar year under this paragraph will be determined in one of the following two ways:

(i) In accordance with 40 CFR Part 75 (relating to continuous emission monitoring), to the extent that the unit was otherwise subject to the requirements of 40 CFR Part 75 for the control period.

(ii) Based on the best available data reported to the Department for the unit, to the extent the unit was not otherwise subject to the requirements of 40 CFR Part 75 for the year.

(2) Except as provided in subparagraphs (iv) and (v), a unit's converted control period heat input for the ozone season portion of a calendar year shall be determined as follows:

(i) The control period gross electrical output of the generators served by the unit multiplied by 7,900 Btu/kWh if the unit is coal-fired for the ozone season control period, and divided by 1,000,000 Btu/mmBtu.

(ii) Not Applicable

(iii) Not Applicable

(iv) Not Applicable

(v) Not Applicable

(vi) Calculations will be based on the best output data available on or before January 31 of the year the allocations are published. If unit level electrical or steam output data are not available from EIA, or submitted by this date by the owner or operator of the CAIR NOx Ozone Season unit, then heat input data for the period multiplied by 0.25 and converted to MWh will be used to determine total output.

(c) Not Applicable

(d) Proration of allowance allocations. The Department will allocate CAIR NOx Ozone Season allowances to each existing CAIR NOx Ozone Season unit and qualifying resource in an amount determined by multiplying the amount of CAIR NOx Ozone Season allowances in the Commonwealth's CAIR NOx Ozone Season trading budget available for allocation under

subsection (c) by the ratio of the baseline heat input of the existing CAIR NOx Ozone Season unit or qualifying resource to the sums of the baseline heat input of existing CAIR NOx Ozone Season units and of the qualifying resources, rounding to the nearest whole allowance as appropriate.
(e) Not Applicable
(f) Not Applicable
(g) The Department will correct any errors in allocations made by the Department and discovered after final allocations are made but before the next allocation cycle, in the subsequent allocation cycle using future allowances that have not yet been allocated.

 # 076 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR NOXsource required to have a title V operating permit and each CAIR NOXunit required to have a title V operating permit at the source shall:
(i) Submit to the permitting authority a complete CAIR permit application under §97.122 in accordance with the deadlines specified in §97.121; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.
(2) The owners and operators of each CAIR NOXsource required to have a title V operating permit and each CAIR NOX unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

 # 077 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(d) Excess emissions requirements. If a CAIR NOXsource emits nitrogen oxides during any control period in excess of the CAIR NOXemissions limitation, then:
(1) The owners and operators of the source and each CAIR NOXunit at the source shall surrender the CAIR NOXallowances required for deduction under §97.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

 # 078 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.106]
Subpart AA - CAIR NOX Annual Trading Program General Provisions
Standard requirements.

(f) Liability. (1) Each CAIR NOXsource and each CAIR NOXunit shall meet the requirements of the CAIR NOXAnnual Trading Program.
(2) Any provision of the CAIR NOXAnnual Trading Program that applies to a CAIR NOXsource or the CAIR designated representative of a CAIR NOXsource shall also apply to the owners and operators of such source and of the CAIR NOXunits at the source.
(3) Any provision of the CAIR NOXAnnual Trading Program that applies to a CAIR NOXunit or the CAIR designated representative of a CAIR NOXunit shall also apply to the owners and operators of such unit.
(g) Effect on other authorities. No provision of the CAIR NOXAnnual Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §97.105 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NOXsource or CAIR NOXunit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

 # 079 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR SO2source required to have a title V operating permit and each CAIR SO2unit required to have a title V operating permit at the source shall:
(i) Submit to the permitting authority a complete CAIR permit application under §97.222 in accordance with the deadlines specified in §97.221; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to

review a CAIR permit application and issue or deny a CAIR permit.
(2) The owners and operators of each CAIR SO2source required to have a title V operating permit and each CAIR SO2unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

 # 080 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(d) Excess emissions requirements. If a CAIR SO2source emits sulfur dioxide during any control period in excess of the CAIR SO2emissions limitation, then:
(1) The owners and operators of the source and each CAIR SO2unit at the source shall surrender the CAIR SO2allowances required for deduction under §97.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

 # 081 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.206]
Subpart AAA - CAIR SO2 Trading Program General Provisions
Standard requirements.

(f) Liability. (1) Each CAIR SO2source and each CAIR SO2unit shall meet the requirements of the CAIR SO2Trading Program.
(2) Any provision of the CAIR SO2Trading Program that applies to a CAIR SO2source or the CAIR designated representative of a CAIR SO2source shall also apply to the owners and operators of such source and of the CAIR SO2units at the source.
(3) Any provision of the CAIR SO2Trading Program that applies to a CAIR SO2unit or the CAIR designated representative of a CAIR SO2unit shall also apply to the owners and operators of such unit.
(g) Effect on other authorities. No provision of the CAIR SO2Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §97.205 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR SO2source or CAIR SO2unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

 # 082 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR NOXOzone Season source required to have a title V operating permit and each CAIR NOXOzone Season unit required to have a title V operating permit at the source shall:
(i) Submit to the permitting authority a complete CAIR permit application under §97.322 in accordance with the deadlines specified in §97.321; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.
(2) The owners and operators of each CAIR NOXOzone Season source required to have a title V operating permit and each CAIR NOXOzone Season unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

 # 083 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

(d) Excess emissions requirements. If a CAIR NOXOzone Season source emits nitrogen oxides during any control period in excess of the CAIR NOXOzone Season emissions limitation, then:
(1) The owners and operators of the source and each CAIR NOXOzone Season unit at the source shall surrender the CAIR NOXOzone Season allowances required for deduction under §97.354(d)(1) and pay any fine, penalty, or assessment or

comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

 # 084 [40 CFR Part 97 NOx Budget Trading Program and CAIR NOx and SO2 Trading Programs §40 CFR 97.306]
Subpart AAAA - CAIR NOX Ozone Season Trading Program General Provisions
Standard requirements.

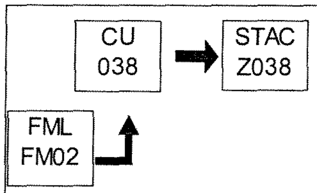
(f) Liability. (1) Each CAIR NOXOzone Season source and each CAIR NOXOzone Season unit shall meet the requirements of the CAIR NOXOzone Season Trading Program.
(2) Any provision of the CAIR NOXOzone Season Trading Program that applies to a CAIR NOXOzone Season source or the CAIR designated representative of a CAIR NOXOzone Season source shall also apply to the owners and operators of such source and of the CAIR NOXOzone Season units at the source.
(3) Any provision of the CAIR NOXOzone Season Trading Program that applies to a CAIR NOXOzone Season unit or the CAIR designated representative of a CAIR NOXOzone Season unit shall also apply to the owners and operators of such unit.
(g) Effect on other authorities. No provision of the CAIR NOXOzone Season Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §97.305 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NOXOzone Season source or CAIR NOXOzone Season unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 038 Source Name: 15 SPACE HEATERS

Source Capacity/Throughput:



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.21]
General
No person may permit the emission from the exhaust of each space heater into the outdoor atmosphere in a manner that the concentration of the sulfur oxides (SOX), expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, dry basis.

Fuel Restriction(s).

 # 002 [25 Pa. Code §127.441]
Operating permit terms and conditions.
The permittee shall only fire #2 or lighter fuel oil in each space heater of Source ID 038.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

 # 003 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

(a) The permittee shall keep records of the data and calculations used to verify compliance with the sulfur oxides (SOx) emissions limitations for Source ID 038.

(b) The permittee shall keep records of the tests conducted or certification reports used to verify the sulfur content (percent by weight) of the fuel oil.

(c) These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

 # 004 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall maintain and operate each space heater of Source ID 038 in accordance with manufacturers specifications.

VII. ADDITIONAL REQUIREMENTS.

 # 005 [25 Pa. Code §127.441]
Operating permit terms and conditions.

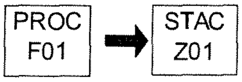
Source ID 038 consists of fifteen #1 and #2 fuel-oil fired space heaters.

*** Permit Shield in Effect. ***

SECTION D. Source Level Requirements

Source ID: F01 Source Name: PLANT HAUL ROADS

Source Capacity/Throughput:



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.441]
Operating permit terms and conditions.

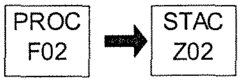
Source ID F01 consists of the various facility roads that are used for transporting coal, oil, ash for disposal, etc. at the facility.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: F02 Source Name: COAL HANDLING AND STORAGE

Source Capacity/Throughput:



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source ID F02 is all coal handling operation at the facility that include: hopper loading, conveying, breaking, transferring, bulldozing, storage, wind erosion, etc. at the facility.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: F03 Source Name: ASH DISPOSAL FACILITY

Source Capacity/Throughput:

PROC F03 → STAC Z03

I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

There shall be no fugitive emissions from the loads contained in the trucks serving the Shawville Station other than what the Department determines to be of minor significance.

Throughput Restriction(s).

 # 002 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

(a) The total amount of ash disposed at the ash disposal facility shall not exceed 261,000 tons in any 12 consecutive month period.

(b) The total amount of soil transferred from the facility property to the ash disposal facility and soil transported from offsite locations to the ash disposal facility (soil borrow) shall not exceed 18,121 tons in any 12 consecutive month period.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

 # 003 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

The permittee shall keep records on a monthly basis of:

(a) The total amount of ash disposed in Source ID F03 in tons and the corresponding 12 consecutive month running total to verify compliance with the ash disposal limitation.

(b) The total amount of soil transferred from the facility property to Source ID F03, the amount of soil transported from offsite locations to Source ID F03 in tons and the corresponding 12 consecutive month running total to verify compliance with the "soil borrow" limitation.

(c) The total amount of miscellaneous coal ash and waste coal disposed of in Source ID F03 in tons.

(d) The total amount of refractory material and concrete construction/demolition waste disposed of in Source ID F03 in tons.

(e) The total amount of sandblast abrasive and residue, other than that which is washed out of the boilers and sluiced to the bottom ash ponds, disposed of in Source ID F03 in tons.

All such records shall be retained for a minimum of five years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

 # 004 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

The raw water supply system at the facility shall provide an adequate supply of water to the fly ash unloaders and paddle mixer associated with the facility's fly ash silos under all plant operating conditions.

 # 005 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

All ash disposed of in Source ID F03 shall be properly conditioned with water prior to disposal. The only fly ash to be disposed of in this ash disposal facility shall be fly ash which has been properly conditioned with water in the fly ash unloaders and paddle mixers associated with the fly ash silos.

 # 006 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

A water truck equipped with both a pressurized spray bar and a pressurized hose or spray nozzle shall be maintained on site at all times. Said water truck shall be used as necessary to minimize fugitive particulate matter emissions from all roadways. The permittee shall implement all winterization measures necessary to render this water truck capable of use under all weather conditions.

 # 007 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

All ash hauled to the disposal facility during the course of a day shall be dumped, spread and compacted by the end of that day.

 # 008 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

All disposal areas shall be covered with soil and/or bottom ash and vegetated upon cessation of active use.

VII. ADDITIONAL REQUIREMENTS.

 # 009 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source ID F03 consists of all ash disposal operations at the Shawville facility including: silo transfer and storage, unloading, spreading, bulldozing, wind erosion, etc. at the facility.

 # 010 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

(a) The only wastes to be disposed of in Source ID F03 shall be the following:

(1) Ash from the Shawville Generating Station or ash from off site coal fired power generation plants.

(2) Miscellaneous coal ash and waste coal, which includes street cleaner refuse, cleaning refuse from ash hopper trenches, vacuum truck boiler refuse and coal spillage, provided the street cleaner refuse and vacuum truck boiler refuse are contained until disposal at the active surface of the disposal site and provided that water is applied to these wastes during disposal, as needed, to control emission of fugitive particulate matter.

(3) Ash pond sediments, which include reject coal and pyrites from the coal mills, water and treatment sludge and wastewater clarifier sludge, provided all these materials contain sufficient moisture content to prevent the emission of fugitive particulate matter during disposal.

(4) Refractory material and concrete concentration/demolition waste provided water is applied, as needed, to control the emission of fugitive particulate matter during disposal.

(5) Sandblast abrasive and residue provided any such material either contains sufficient moisture content to prevent the emission of particulate matter during disposal or water is applied to the material, as needed, to control the emission of particulate matter during disposal.

(6) Filter media/spent demineralization resin provided this material contains sufficient moisture content to prevent the emission of particulate matter during disposal.

(7) Asbestos-containing waste provided it is classified as non-friable and is double wrapped in plastic.

(b) The permittee shall not dispose of any other types of wastes in Source ID F03 unless prior approval is granted from the Department's Air Quality and Waste Management Programs.

 # 011 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 127.1 and 127.12]

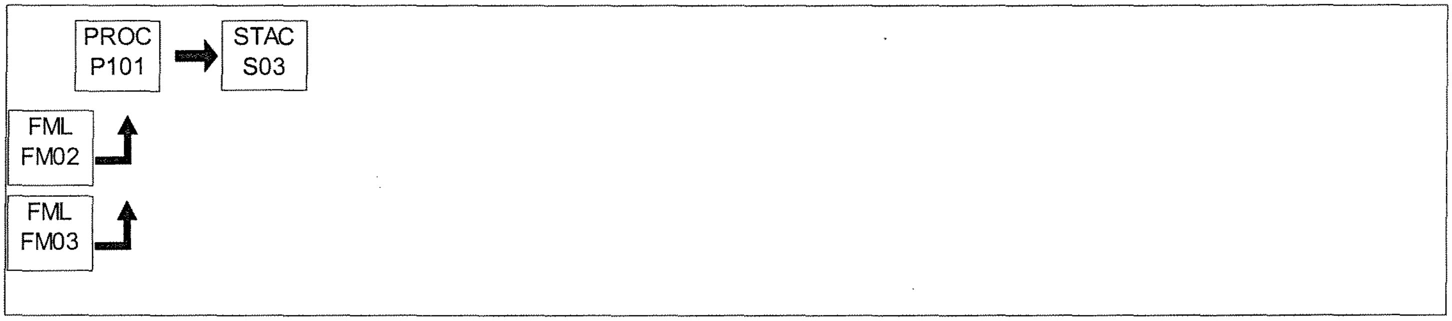
All trucks transporting ash from all offsite locations shall be fully tarped (affixed with a tarp covering the entire truck bed opening) during all times of transport.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: P101 Source Name: STARTUP GENERATOR 5

Source Capacity/Throughput:



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.13]
Processes
No person shall permit the emission of particulate matter from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of particulate matter in the effluent gas exceeds 0.04 grain per dry standard cubic foot.

 # 002 [25 Pa. Code §123.21]
General
No person may permit the emission from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of the sulfur oxides (SOX), expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, dry basis.

Fuel Restriction(s).

 # 003 [25 Pa. Code §127.441]
Operating permit terms and conditions.
The permittee shall only fire #2 or lighter fuel oil in Source ID P101.

Operation Hours Restriction(s).

 # 004 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall limit the operation of Source ID P101 to less than a 5% capacity factor in any 12 consecutive month period.

 # 005 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is also derived from the permittee's election to restrict the operation of each of the start-up engines (Source IDs P101 through P103) to less than 100 hours in order to comply with 40 CFR Part 63 Subpart ZZZZ]

[Compliance with this streamlined permit condition will assure compliance with 40 CFR Part 63 Subpart ZZZZ for existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions]

Effective on May 3, 2013, each engine associated with Source IDs P101 through P103 shall operate less than 100 hours in any 12 consecutive month period.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

 # 006 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95. The records shall clearly demonstrate that the annual capacity factor for Source ID P101 is less than 5%.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

 # 007 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Compliance with item (c) of this streamlined permit condition will assure compliance with 40 CFR Part 63 Subpart ZZZZ for existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions]

(a) The permittee shall keep records of the data and calculations used to verify compliance with the particulate matter and sulfur oxides (SOx) emissions limitations for Source ID P101.

(b) The permittee shall keep records of the tests conducted or certification reports used to verify the sulfur content (percent by weight) of the fuel oil.

(c) The permittee shall keep records of the engine's hours of operation taken from the non-resettable hour meter and 12-consecutive month hours of operation on a monthly basis to very compliance with the operational limitation listed under the section titled I. Operation Hours Restriction(s) above.

(d) These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

 # 008 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall annually report records of supporting calculations that clearly demonstrate that the annual capacity factor for Source ID P101 is less than 5%.

Annual reports shall be submitted to the Department by no later than March 1 for the preceeding year.

VI. WORK PRACTICE REQUIREMENTS.

 # 009 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall maintain and operate Source ID P101 in accordance with the manufacturers specifications.

VII. ADDITIONAL REQUIREMENTS.

 # 010 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID P101 (Unit 5) is a 2880 hp, General Motors diesel engine.

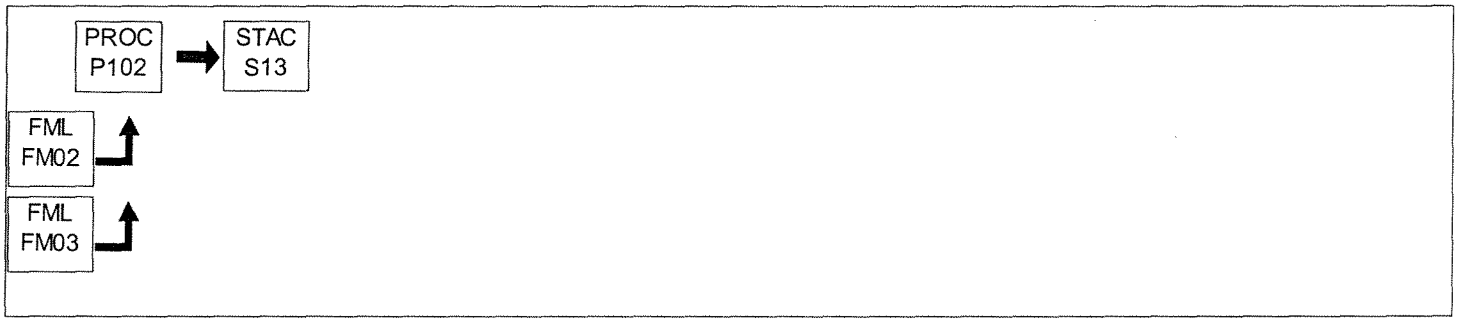
 # 011 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Effective on May 3, 2013, each engine associated with Source IDs P101 through P103 will be defined as an limited use stationary RICE per 40 CFR § 63.6675 that are located at a major source of hazardous air pollutants, and therefore, do not have to meet any requirements in 40 CFR Part 63 Subpart ZZZZ and Subpart A, including initial notification requirements pursuant to 40 CFR § 63.6590(b)(3).

***** Permit Shield in Effect. *****

Source ID: P102 Source Name: STARTUP GENERATOR 6

Source Capacity/Throughput:



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.13]
Processes
No person shall permit the emission of particulate matter from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of particulate matter in the effluent gas exceeds 0.04 grain per dry standard cubic foot.

 # 002 [25 Pa. Code §123.21]
General
No person may permit the emission from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of the sulfur oxides (SOX), expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, dry basis.

Fuel Restriction(s).

 # 003 [25 Pa. Code §127.441]
Operating permit terms and conditions.
The permittee shall only fire #2 or lighter fuel oil in Source ID P102.

Operation Hours Restriction(s).

 # 004 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall limit the operation of Source ID P102 to less than a 5% capacity factor in any 12 consecutive month period.

 # 005 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is also derived from the permittee's election to restrict the operation of each of the start-up engines (Source IDs P101 through P103) to less than 100 hours in order to comply with 40 CFR Part 63 Subpart ZZZZ]

[Compliance with this streamlined permit condition will assure compliance with 40 CFR Part 63 Subpart ZZZZ for existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions]

Effective on May 3, 2013, each engine associated with Source IDs P101 through P103 shall operate less than 100 hours in any 12 consecutive month period.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

 # 006 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95. The records shall clearly demonstrate that the annual capacity factor for Source ID P102 is less than 5%.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

 # 007 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Compliance with item (c) of this streamlined permit condition will assure compliance with 40 CFR Part 63 Subpart ZZZZ for existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions]

(a) The permittee shall keep records of the data and calculations used to verify compliance with the particulate matter and sulfur oxides (SOx) emissions limitations for Source ID P102.

(b) The permittee shall keep records of the tests conducted or certification reports used to verify the sulfur content (percent by weight) of the fuel oil.

(c) The permittee shall keep records of the engine's hours of operation taken from the non-resettable hour meter and 12-consecutive month hours of operation on a monthly basis to very compliance with the operational limitation listed under the section titled I. Operation Hours Restriction(s) above.

(d) These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

 # 008 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall annually report records of supporting calculations that clearly demonstrate that the annual capacity factor for Source ID P102 is less than 5%.

Annual reports shall be submitted to the Department by no later than March 1 for the preceeding year.

VI. WORK PRACTICE REQUIREMENTS.

 # 009 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall maintain and operate Source ID P102 in accordance with the manufacturers specifications.

VII. ADDITIONAL REQUIREMENTS.

 # 010 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID P102 (Unit 6) is a 2880 hp, General Motors diesel engine.

 # 011 [25 Pa. Code §127.441]
Operating permit terms and conditions.

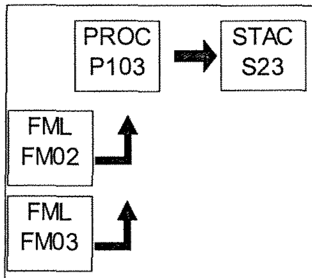
Effective on May 3, 2013, each engine associated with Source IDs P101 through P103 will be defined as an limited use stationary RICE per 40 CFR § 63.6675 that are located at a major source of hazardous air pollutants, and therefore, do not have to meet any requirements in 40 CFR Part 63 Subpart ZZZZ and Subpart A, including initial notification requirements pursuant to 40 CFR § 63.6590(b)(3).

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: P103 Source Name: STARTUP GENERATOR 7

Source Capacity/Throughput:



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.13]
Processes
No person shall permit the emission of particulate matter from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of particulate matter in the effluent gas exceeds 0.04 grain per dry standard cubic foot.

 # 002 [25 Pa. Code §123.21]
General
No person may permit the emission from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of the sulfur oxides (SOX), expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, dry basis.

Fuel Restriction(s).

 # 003 [25 Pa. Code §127.441]
Operating permit terms and conditions.
The permittee shall only fire #2 or lighter fuel oil in Source ID P103.

Operation Hours Restriction(s).

 # 004 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall limit the operation of Source ID P103 to less than a 5% capacity factor in any 12 consecutive month period.

 # 005 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is also derived from the permittee's election to restrict the operation of each of the start-up engines (Source IDs P101 through P103) to less than 100 hours in order to comply with 40 CFR Part 63 Subpart ZZZZ]

[Compliance with this streamlined permit condition will assure compliance with 40 CFR Part 63 Subpart ZZZZ for existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions]

Effective on May 3, 2013, each engine associated with Source IDs P101 through P103 shall operate less than 100 hours in any 12 consecutive month period.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

 # 006 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95. The records shall clearly demonstrate that the annual capacity factor for Source ID P103 is less than 5%.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

 # 007 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Compliance with item (c) of this streamlined permit condition will assure compliance with 40 CFR Part 63 Subpart ZZZZ for existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions]

(a) The permittee shall keep records of the data and calculations used to verify compliance with the particulate matter and sulfur oxides (SOx) emissions limitations for Source ID P103.

(b) The permittee shall keep records of the tests conducted or certification reports used to verify the sulfur content (percent by weight) of the fuel oil.

(c) The permittee shall keep records of the engine's hours of operation taken from the non-resettable hour meter and 12-consecutive month hours of operation on a monthly basis to very compliance with the operational limitation listed under the section titled I. Operation Hours Restriction(s) above.

(d) These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

V. REPORTING REQUIREMENTS.

 # 008 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

The permittee shall annually report records of supporting calculations that clearly demonstrate that the annual capacity factor for Source ID P103 is less than 5%.

Annual reports shall be submitted to the Department by no later than March 1 for the preceeding year.

VI. WORK PRACTICE REQUIREMENTS.

 # 009 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall maintain and operate Source ID P103 in accordance with the manufacturers specifications.

VII. ADDITIONAL REQUIREMENTS.

 # 010 [25 Pa. Code §127.441]

Operating permit terms and conditions.

Source ID P103 (Unit 7) is a 2880 hp, General Motors diesel engine.

 # 011 [25 Pa. Code §127.441]
Operating permit terms and conditions.

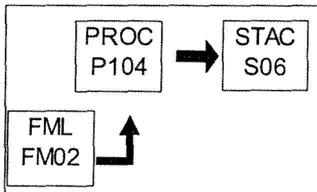
Effective on May 3, 2013, each engine associated with Source IDs P101 through P103 will be defined as an limited use stationary RICE per 40 CFR § 63.6675 that are located at a major source of hazardous air pollutants, and therefore, do not have to meet any requirements in 40 CFR Part 63 Subpart ZZZZ and Subpart A, including initial notification requirements pursuant to 40 CFR § 63.6590(b)(3).

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: P104 Source Name: EMERGENCY GENERATOR 1(UNIT 1-2)

Source Capacity/Throughput:



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.13]
Processes
No person shall permit the emission of particulate matter from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of particulate matter in the effluent gas exceeds 0.04 grain per dry standard cubic foot.

 # 002 [25 Pa. Code §123.21]
General
No person may permit the emission from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of the sulfur oxides (SOX), expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, dry basis.

Fuel Restriction(s).

 # 003 [25 Pa. Code §127.441]
Operating permit terms and conditions.
The permittee shall only fire #2 or lighter fuel oil in Source ID P104.

Operation Hours Restriction(s).

 # 004 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall limit the operation of Source ID P104 to less than 500 hours in any 12 consecutive month period.

 # 005 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6625]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
What are my monitoring, installation, operation, and maintenance requirements?
In accordance with the provisions from 40 CFR § 63.6625(h), the permittee shall minimize this engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes.

 # 006 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6640]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
How do I demonstrate continuous compliance with the emission limitations and operating limitations?
(f) The permittee shall operate each of the emergency stationary RICE associated with Source IDs P104, P106 and P120 according to the requirements in paragraphs (f)(1)(i) through (iii) of this section. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1)(i) through (iii) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) The permittee may operate each emergency stationary RICE 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.

(iii) The permittee may operate each emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

 # 007 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6625]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
What are my monitoring, installation, operation, and maintenance requirements?

(a) In accordance with the provisions from 40 CFR § 63.6625(i), the permittee may utilize an oil analysis program in order to extend the oil change requirement listed below under VI. Work Practice Requirements.

(1) The oil analysis shall be performed at the same frequency specified for changing the oil (i.e. every 500 hours of operation or annually, whichever comes first).

(2) The analysis program shall at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content.

(i) The condemning limits for these parameters are as follows:
(A) Total Base Number is less than 30 percent of the Total Base Number of the oil when new;
(B) Viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new;
(C) Percent water content (by volume) is greater than 0.5.

(ii) If all of these condemning limits are not exceeded, the permittee is not required to change the oil.
(iii) If any of the limits are exceeded, the permittee shall change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the permittee shall change the oil within 2 days or before commencing operation, whichever is later.

IV. RECORDKEEPING REQUIREMENTS.

 # 008 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95. The records shall, at a minimum, include data that clearly demonstrates that Source ID P104 has operated less than 500 hours in any twelve consecutive month period.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

 # 009 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall comply with all applicable recordkeeping requirements of 40 CFR § 63.6655.

 # 010 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

(a) The permittee shall keep records of the data and calculations used to verify compliance with the particulate matter and sulfur oxides (SOx) emissions limitations for Source ID P104.

(b) The permittee shall keep records of the tests conducted or certification reports used to verify the sulfur content (percent by weight) of the fuel oil.

(c) These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

 # 011 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6625]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
What are my monitoring, installation, operation, and maintenance requirements?

(a) In accordance with the provisions of 40 CFR § 63.6625(i), the permittee shall keep records of the parameters that are analyzed as part of the oil analysis program, the results of the analysis, and the oil changes for the engine. The oil analysis program shall be part of the maintenance plan for the engine.

(b) All information used to comply with this recordkeeping condition shall be kept for minimum period of five (5) years and shall be available upon request.

 # 012 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6655]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
What records must I keep?

(a) In accordance with 40 CFR § 63.6655(e), the permittee shall keep records of the maintenance conducted on the each engine associated with Source IDs P104, P106, and P120 in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to the respective maintenance plan

(b) In accordance with 40 CFR § 63.6655(f), the permittee shall keep records of the hours of operation of this engine that is recorded through the non-resettable hour meter.
(1) The permittee shall document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.
(2) If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.

V. REPORTING REQUIREMENTS.

 # 013 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall report annually the total number of hours that the subject source has been operated.

(b) Annual report shall be submitted to the Department no later than March 1 for the preceding year.

 # 014 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 40 CFR § 63.6595(c)]

The permittee shall comply with the applicable notification requirements in § 63.6645 and in 40 CFR part 63, subpart A.

 # 015 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall comply with all applicable reporting requirements of 40 CFR § 63.6650.

VI. WORK PRACTICE REQUIREMENTS.

 # 016 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall maintain and operate the Source ID P104 in accordance with manufacturers specifications.

 # 017 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 40 CFR § 63.6602]

(a) Except for the option to utilize an oil analysis program to extend the oil change requirement as specified above, the permittee shall perform the following work practice requirements to each engine associated with Source IDs P104, P106 and P120.

(1) Change oil and filter every 500 hours of operation or annually, whichever comes first
(2) Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;
(3) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

(b) Pursuant to 40 CFR § 63.6(g), the permittee may submit a petition to request alternative work practice requirements.

 # 018 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6625]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
What are my monitoring, installation, operation, and maintenance requirements?

In accordance with the provisions from 40 CFR § 63.6625(f), the permittee shall install a non-resettable hour meter on this engine prior to May 3, 2013 if one is not already installed.

VII. ADDITIONAL REQUIREMENTS.

 # 019 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source ID P104 (Unit 1-2) consists of a model #62400RA, 254 horsepower, General Motors diesel emergency generator.

 # 020 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 63.6580]

(a) Source ID P104 is subject to 40 CFR Part 63, Subpart ZZZZ.

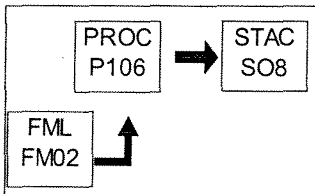
(b) The permittee shall comply with all the applicable requirements specified in 40 CFR Sections 63.6580 through 63.6675.

(b) Pursuant to 40 CFR § 63.6595(a)(1), the compliance date for Source ID P104 is May 3, 2013.

***** Permit Shield in Effect. *****

Source ID: P106 Source Name: 2 FIRE PUMP ENGINES

Source Capacity/Throughput:



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.13]
Processes
No person shall permit the emission of particulate matter from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of particulate matter in the effluent gas exceeds 0.04 grain per dry standard cubic foot.

 # 002 [25 Pa. Code §123.21]
General
No person may permit the emission from the exhaust of the subject source into the outdoor atmosphere in a manner that the concentration of the sulfur oxides (SOX), expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, dry basis.

Fuel Restriction(s).

 # 003 [25 Pa. Code §127.441]
Operating permit terms and conditions.
The permittee shall only fire #2 or lighter fuel oil in each engine of Source ID P106.

Operation Hours Restriction(s).

 # 004 [25 Pa. Code §127.441]
Operating permit terms and conditions.
[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall limit the operation of each engine of Source ID P106 to less than 500 hours in any 12 consecutive month period.

 # 005 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6625]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
What are my monitoring, installation, operation, and maintenance requirements?
In accordance with the provisions from 40 CFR § 63.6625(h), the permittee shall minimize this engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes.

 # 006 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6640]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
How do I demonstrate continuous compliance with the emission limitations and operating limitations?
(f) The permittee shall operate each of the emergency stationary RICE associated with Source IDs P104, P106 and P120 according to the requirements in paragraphs (f)(1)(i) through (iii) of this section. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1)(i) through (iii) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) The permittee may operate each emergency stationary RICE 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.

(iii) The permittee may operate each emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

 # 007 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6625]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
What are my monitoring, installation, operation, and maintenance requirements?

(a) In accordance with the provisions from 40 CFR § 63.6625(i), the permittee may utilize an oil analysis program in order to extend the oil change requirement listed below under VI. Work Practice Requirements.

(1) The oil analysis shall be performed at the same frequency specified for changing the oil (i.e. every 500 hours of operation or annually, whichever comes first).

(2) The analysis program shall at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content.

(i) The condemning limits for these parameters are as follows:
(A) Total Base Number is less than 30 percent of the Total Base Number of the oil when new;
(B) Viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new;
(C) Percent water content (by volume) is greater than 0.5.

(ii) If all of these condemning limits are not exceeded, the permittee is not required to change the oil.
(iii) If any of the limits are exceeded, the permittee shall change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the permittee shall change the oil within 2 days or before commencing operation, whichever is later.

IV. RECORDKEEPING REQUIREMENTS.

 # 008 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.95 and 127.511]

The permittee shall keep records in accordance with the provisions specified in 25 Pa. Code Sections 129.91-129.95. The records shall, at a minimum, include data that clearly demonstrates that each engine of Source ID P106 has operated less than 500 hours in any twelve consecutive month period.

These records shall be retained for a minimum of 5 years and shall be made available to the Department upon request.

 # 009 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall comply with all applicable recordkeeping requirements of 40 CFR § 63.6655.

 # 010 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6625]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
What are my monitoring, installation, operation, and maintenance requirements?

(a) In accordance with the provisions of 40 CFR § 63.6625(i), the permittee shall keep records of the parameters that are analyzed as part of the oil analysis program, the results of the analysis, and the oil changes for the engine. The oil analysis program shall be part of the maintenance plan for the engine.

(b) All information used to comply with this recordkeeping condition shall be kept for minimum period of five (5) years and shall be available upon request.

 # 011 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6655]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
What records must I keep?

(a) In accordance with 40 CFR § 63.6655(e), the permittee shall keep records of the maintenance conducted on the each engine associated with Source IDs P104, P106, and P120 in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to the respective maintenance plan

(b) In accordance with 40 CFR § 63.6655(f), the permittee shall keep records of the hours of operation of this engine that is recorded through the non-resettable hour meter.
(1) The permittee shall document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.
(2) If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.

V. REPORTING REQUIREMENTS.

 # 012 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 127.511]

(a) The permittee shall report annually the total number of hours that the subject source has been operated.

(b) Annual report shall be submitted to the Department no later than March 1 for the preceding year.

 # 013 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 40 CFR § 63.6595(c)]

The permittee shall comply with the applicable notification requirements in § 63.6645 and in 40 CFR part 63, subpart A.

 # 014 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall comply with all applicable reporting requirements of 40 CFR § 63.6650.

SECTION D. Source Level Requirements

VI. WORK PRACTICE REQUIREMENTS.

 # 015 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Sections 129.91 and 129.93]

The permittee shall maintain and operate each engine of Source ID P106 in accordance with manufacturers specifications.

 # 016 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 40 CFR § 63.6602]

(a) Except for the option to utilize an oil analysis program to extend the oil change requirement as specified above, the permittee shall perform the following work practice requirements to each engine associated with Source IDs P104, P106 and P120.

(1) Change oil and filter every 500 hours of operation or annually, whichever comes first
(2) Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;
(3) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

(b) Pursuant to 40 CFR § 63.6(g), the permittee may submit a petition to request alternative work practice requirements.

 # 017 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6625]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
What are my monitoring, installation, operation, and maintenance requirements?

In accordance with the provisions from 40 CFR § 63.6625(f), the permittee shall install a non-resettable hour meter on this engine prior to May 3, 2013 if one is not already installed.

VII. ADDITIONAL REQUIREMENTS.

 # 018 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source ID P106 is 2 model #NT-380-IF, 283 horsepower, Cummings diesel fire pump engines.

 # 019 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 63.6580]

(a) Source ID P106 is subject to 40 CFR Part 63, Subpart ZZZZ.

(b) The permittee shall comply with all the applicable requirements specified in 40 CFR Sections 63.6580 through 63.6675.

(b) Pursuant to 40 CFR § 63.6595(a)(1), the compliance date for Source ID P106 is May 3, 2013.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: P116 Source Name: WATER TREATMENT OPERATIONS

Source Capacity/Throughput:

PROC P116 → STAC Z116

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.441]
Operating permit terms and conditions.

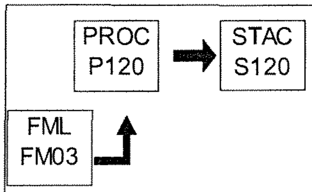
The water treatment operations of P116 include all activities and processes associated with treating wastewater at the facility. It includes: the lime silo with fabric filter, clarifying pools, mixing and settling tanks, all pH adjustment proceedures and all other wastewater treatment conducted at the facility.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: P120 Source Name: EMERGENCY DIESEL GENERATOR

Source Capacity/Throughput:



I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.13]
Processes
No person may permit the emission into the outdoor atmosphere of particulate matter from the exhaust associated with Source ID P120 in a manner that the concentration in the effluent gas exceeds 0.04 grains per dry standard cubic foot.

 # 002 [25 Pa. Code §123.21]
General
No person may permit the emission into the outdoor atmosphere of sulfur oxides from Source ID P120 in a manner that the concentration of the sulfur oxides, expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, on a dry basis.

Fuel Restriction(s).

 # 003 [25 Pa. Code §127.441]
Operating permit terms and conditions.
Source ID P120 shall only be fired on No. 2 fuel oil.

Operation Hours Restriction(s).

 # 004 [25 Pa. Code §127.441]
Operating permit terms and conditions.
Source ID P120 shall not be operated in excess of 500 hours in any 12 consecutive month period.

 # 005 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6625]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
What are my monitoring, installation, operation, and maintenance requirements?
In accordance with the provisions from 40 CFR § 63.6625(h), the permittee shall minimize this engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes.

 # 006 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6640]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
How do I demonstrate continuous compliance with the emission limitations and operating limitations?
(f) The permittee shall operate each of the emergency stationary RICE associated with Source IDs P104, P106 and P120 according to the requirements in paragraphs (f)(1)(i) through (iii) of this section. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1)(i) through (iii) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) The permittee may operate each emergency stationary RICE 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.

(iii) The permittee may operate each emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

 # 007 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6625]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
What are my monitoring, installation, operation, and maintenance requirements?

(a) In accordance with the provisions from 40 CFR § 63.6625(i), the permittee may utilize an oil analysis program in order to extend the oil change requirement listed below under VI. Work Practice Requirements.

(1) The oil analysis shall be performed at the same frequency specified for changing the oil (i.e. every 500 hours of operation or annually, whichever comes first).

(2) The analysis program shall at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content.

(i) The condemning limits for these parameters are as follows:
(A) Total Base Number is less than 30 percent of the Total Base Number of the oil when new;
(B) Viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new;
(C) Percent water content (by volume) is greater than 0.5.

(ii) If all of these condemning limits are not exceeded, the permittee is not required to change the oil.
(iii) If any of the limits are exceeded, the permittee shall change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the permittee shall change the oil within 2 days or before commencing operation, whichever is later.

IV. RECORDKEEPING REQUIREMENTS.

 # 008 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall keep comprehensive and accurate records of the following:

(a) The amount of hours that Source ID P120 is operated each month and keep calculations which verify the 12 consecutive month operational limitation for Source ID P120.

(b) Supporting calculations to verify compliance with the particulate matter and sulfur oxide emission limitations for Source

ID P120.

These records shall be retained for a minimum of five years and shall be made available to the Department upon request.

 # 009 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall comply with all applicable recordkeeping requirements of 40 CFR § 63.6655.

 # 010 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6625]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
What are my monitoring, installation, operation, and maintenance requirements?

(a) In accordance with the provisions of 40 CFR § 63.6625(i), the permittee shall keep records of the parameters that are analyzed as part of the oil analysis program, the results of the analysis, and the oil changes for the engine. The oil analysis program shall be part of the maintenance plan for the engine.

(b) All information used to comply with this recordkeeping condition shall be kept for minimum period of five (5) years and shall be available upon request.

 # 011 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6655]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
What records must I keep?

(a) In accordance with 40 CFR § 63.6655(e), the permittee shall keep records of the maintenance conducted on the each engine associated with Source IDs P104, P106, and P120 in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to the respective maintenance plan

(b) In accordance with 40 CFR § 63.6655(f), the permittee shall keep records of the hours of operation of this engine that is recorded through the non-resettable hour meter.
(1) The permittee shall document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.
(2) If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.

V. REPORTING REQUIREMENTS.

 # 012 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 40 CFR § 63.6595(c)]

The permittee shall comply with the applicable notification requirements in § 63.6645 and in 40 CFR part 63, subpart A.

 # 013 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall comply with all applicable reporting requirements of 40 CFR § 63.6650.

VI. WORK PRACTICE REQUIREMENTS.

 # 014 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 40 CFR § 63.6602]

(a) Except for the option to utilize an oil analysis program to extend the oil change requirement as specified above, the permittee shall perform the following work practice requirements to each engine associated with Source IDs P104, P106 and P120.

(1) Change oil and filter every 500 hours of operation or annually, whichever comes first

(2) Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;
(3) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

(b) Pursuant to 40 CFR § 63.6(g), the permittee may submit a petition to request alternative work practice requirements.

 # 015 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.6625]
Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
What are my monitoring, installation, operation, and maintenance requirements?

In accordance with the provisions from 40 CFR § 63.6625(f), the permittee shall install a non-resettable hour meter on this engine prior to May 3, 2013 if one is not already installed.

VII. ADDITIONAL REQUIREMENTS.

 # 016 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source ID P120 is a diesel fired Caterpillar model D200P3 emergency generator rated at 242 kilowatts

 # 017 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR Section 63.6580]

(a) Source ID P120 is subject to 40 CFR Part 63, Subpart ZZZZ.

(b) The permittee shall comply with all the applicable requirements specified in 40 CFR Sections 63.6580 through 63.6675.

(b) Pursuant to 40 CFR § 63.6595(a)(1), the compliance date for Source ID P120 is May 3, 2013.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: P121 Source Name: PARTS WASHERS

Source Capacity/Throughput:

PROC P121 → STAC Z121

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

 # 001 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 129.63]

The permittee shall keep records of Certified Product Data Sheets (CPDSs) or Material Safety Data Sheets (MSDSs) that identify the volatile organic compound (VOC) and HAP content of the solvents used in Source ID P121.

 # 002 [25 Pa. Code §129.63]
Degreasing operations

The permittee shall maintain for a minimum of five (5) years and present to the Department upon request the following information:

(1) The name and address of the solvent supplier,

(2) The type of solvent including the product or vendor identification number,

(3) The vapor pressure of the solvent measured in millimeters of mercury (mm Hg) at 68 degrees Fahrenheit.

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

 # 003 [25 Pa. Code §129.63]
Degreasing operations

Each parts washer of Source ID P121 shall be operated in accordance with the following procedures:

(1) Waste solvent shall be collected and stored in a closed container. The closed container may contain a device that allows pressure relief, but does not allow liquid solvent to drip from the container.

(2) Flushing of parts using a flexible hose or other flushing device shall be performed only within the cold cleaning machine.

The solvent spray shall be a solid fluid stream, not an atomized or shower spray.

(3) Sponges, fabric, wood, leather, paper products, and other absorbent materials may not be cleaned in the cold cleaning machine.

(4) Air agitated solvent baths may not be used.

(5) Spills during solvent transfer and use of cold cleaning machine shall be cleaned up immediately.

VII. ADDITIONAL REQUIREMENTS.

 # 004 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source ID P121 is subject to 25 Pa. Code Section 129.63(a) (Degreasing Operations - Cold Cleaning Machines). The permittee shall comply with all applicable requirements specified in 25 Pa. Code Section 129.63(a).

 # 005 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 25 Pa. Code Section 129.63]

The vapor pressure of VOC containing solvent shall be less than 1.0 millimeter of mercury (mm Hg) measured at 20 degrees Celsius (68 degrees Fahrenheit).

 # 006 [25 Pa. Code §127.441]
Operating permit terms and conditions.

Source ID P121 consists of two (2) parts washers used in the shop area.

 # 007 [25 Pa. Code §129.63]
Degreasing operations

Each parts washer of Source ID P121 shall have a freeboard ratio of 0.50 or greater.

 # 008 [25 Pa. Code §129.63]
Degreasing operations

Each parts washer of Source ID P121 shall have a permanent, conspicuous label summarizing all required operating procedures specified in Condition #003 for Source ID P121. In addition, the label shall include the following discretionary good operating practices:

(1) Cleaned parts should be drained at least 15 seconds or until dripping ceases, whichever is longer. Parts having cavities or blind holes shall be tipped or rotated while the part is draining.

(2) During the draining, tipping, or rotating, the parts should be positioned so that solvent drains directly back to the cold cleaning machine.

(3) Work area fans should be located and positioned so that they do not blow across the opening of the degreaser unit.

 # 009 [25 Pa. Code §129.63]
Degreasing operations

Each parts washer of Source ID P121 shall be equipped with a cover that shall be closed at all times except during the cleaning of parts or the addition or removal of solvent. For Source ID P121, a perforated drain with a diameter of not more than 6 inches shall constitute an acceptable cover.

***** Permit Shield in Effect. *****

SECTION E. Alternative Operation Requirements.

No Alternative Operations exist for this Title V facility.

SECTION F. Emission Restriction Summary.

Source Id	Source Description
031	UTILITY BOILER - UNIT 1

Emission Limit			Pollutant
0.003	Lbs/MMBTU	ammonia	Ammonia (Aqueous Soll Conc. 20
5.000	PPMV	corrected to 8% oxygen	Ammonia (Aqueous Soll Conc. 20
0.524	Lbs/MMBTU	30-day rolling average	NOX
3.700	Lbs/MMBTU	30-day rolling average	SOX
4.000	Lbs/MMBTU	2 day ave. in any 30 days	SOX
4.000	Lbs/MMBTU	at any time	SOX
4.800	Lbs/MMBTU	daily average	SOX
0.100	Lbs/MMBTU		TSP

Source Id	Source Description
032	UTILITY BOILER - UNIT 2

Emission Limit			Pollutant
0.003	Lbs/MMBTU	ammonia	Ammonia (Aqueous Soll Conc. 20
5.000	PPMV	corrected to 8% oxygen	Ammonia (Aqueous Soll Conc. 20
0.542	Lbs/MMBTU	30-day rolling average	NOX
3.700	Lbs/MMBTU	30-day rolling average	SOX
4.000	Lbs/MMBTU	2 day ave. in any 30 days	SOX
4.000	Lbs/MMBTU	at any time	SOX
4.800	Lbs/MMBTU	daily average	SOX
0.100	Lbs/MMBTU		TSP

Source Id	Source Description
033	UTILITY BOILER - UNIT 3

Emission Limit			Pollutant
5.000	PPMV	corrected to 8% oxygen	Ammonia (Aqueous Soll Conc. 20
0.450	Lbs/MMBTU	30-day rolling average	NOX
3.700	Lbs/MMBTU	30-day rolling average	SOX
4.000	Lbs/MMBTU	2 day ave. in any 30 days	SOX
4.000	Lbs/MMBTU	at any time	SOX
4.800	Lbs/MMBTU	daily average	SOX
0.100	Lbs/MMBTU		TSP

Source Id	Source Description
034	UTILITY BOILER - UNIT 4

Emission Limit			Pollutant
5.000	PPMV	corrected to 8% oxygen	Ammonia (Aqueous Soll Conc. 20
0.450	Lbs/MMBTU	30-day rolling average	NOX
3.700	Lbs/MMBTU	30-DAY ROLLING AVERAGE	SOX
4.000	Lbs/MMBTU	2 day ave. in any 30 days	SOX
4.000	Lbs/MMBTU	AT ANY TIME	SOX
4.800	Lbs/MMBTU	daily average	SOX
0.100	Lbs/MMBTU		TSP

Source Id	Source Description
038	15 SPACE HEATERS

Emission Limit			Pollutant
500.000	PPMV		SOX

SECTION F. Emission Restriction Summary.

Source Id	Source Descriptior
P101	STARTUP GENERATOR 5

Emission Limit		Pollutant
500.000	PPMV	SOX
0.040	gr/DRY FT3	TSP

Source Id	Source Descriptior
P102	STARTUP GENERATOR 6

Emission Limit		Pollutant
500.000	PPMV	SOX
0.040	gr/DRY FT3	TSP

Source Id	Source Descriptior
P103	STARTUP GENERATOR 7

Emission Limit		Pollutant
500.000	PPMV	SOX
0.040	gr/DRY FT3	TSP

Source Id	Source Descriptior
P104	EMERGENCY GENERATOR 1(UNIT 1-2)

Emission Limit		Pollutant
500.000	PPMV	SOX
0.040	gr/DRY FT3	TSP

Source Id	Source Descriptior
P106	2 FIRE PUMP ENGINES

Emission Limit		Pollutant
500.000	PPMV	SOX
0.040	gr/DRY FT3	TSP

Source Id	Source Descriptior
P120	EMERGENCY DIESEL GENERATOR

Emission Limit		Pollutant
500.000	PPMV	SOX
0.040	gr/DRY FT3	TSP

Site Emission Restriction Summary

Emission Limit	Pollutant

SECTION G. Miscellaneous.

(1) The following air contaminant sources are considered to be of minor significance to the Department and have been determined to be exempt from permit requirements. However, this determination does not exempt the sources from compliance with all applicable air quality regulations specified in 25 Pa. Code Chapters 121-143:

(a) There are 12 storage tanks at this facility that have a capacity that is less than 2000 gallons. They include:

1. ash landfill area diesel fuel oil storage tank - 1000 gallon
2. ash landfill area gasoline storage tank - 500 gallon
3. ash landfill area waste oil tank - 250 gallon
4. ash landfill area waste oil tank - 300 gallon
5. 2 ash landfill area lube oil tanks - 500 gallon each
6. sulfuric acid storage tank - 1,000 gallon
7. 5 day-tanks for generators - 100 gallons each

(b) There are 15 storage tanks at this facility that have a capacity that is greater than 2000 gallons used to store liquids having vapor pressures less than 1.5 psia. They include:

1. #2 oil storage tank - 500,000 gallons
2. 2 startup diesel (a blend of #1 and #2 fuel oil) fuel storage tanks - 20,000 gallons each
3. 2 waste oil storage tanks - 3,000 gallons each
4. 3 lube oil storage tanks - 5,000 gallons each
5. an ethylene glycol storage tank - 5,000 gallons
6. a 6% caustic storage tank - 5,000 gallons
7. a 50% caustic storage tank - 2,800 gallons
8. a 50% caustic storage tank - 10,000 gallons
9. a FWWT 20% caustic storage tank - 7,500 gallons
10. a Sulfuric acid storage tank - 10,000 gallons
11. an Anhydrous ammonia storage tank - 10,000 gallons

(c) 2 mechanical draft cooling towers.

(d) Fly ash silos and Limestone silos.

(2) Attached to this permit is the Phase II Title IV (Acid Rain) permit in its entirety, renewed on May 29, 2009 and effective through December 31, 2012. Certain requirements from the Acid Rain permit have been reiterated in the body of the Title V permit for emphasis. The entire Title IV permit is incorporated into this Title V permit by inclusion.

(3) The applicable emission restrictions and operating requirements for the Shawville Generating Station are set forth in Sections C through G of this permit. The general Title V requirements of Section B in this permit continue in full force and effect.

(4) GenON announced the realignment of operational responsibilities and reporting structure as specified in a letter dated May 11, 2011. The letter also requested update to the following list, which identifies additional responsible officials for the Shawville Generating Station.

Name	Title	Address	Telephone
Steve Davies	President	121 Champion Way, Suite 200 Canonsburg, PA 15317 Steve.Davies@genon.com	724-597-8362
James V. Locher	Vice President	121 Champion Way, Suite 200 Canonsburg, PA 15317 James.Locher@genon.com	724-597-8547
James P. Garlick	Vice President	1000 Main Houston, TX 77002 James.Garlick@genon.com	832-357-5434
Kevin P. Boudreaux	Vice President	1000 Main Houston, TX 77002	832-357-3670

SECTION G. Miscellaneous.

		Kevin.Boudreaux@genon.com	
Matthew P. Pistner	Vice President	121 Champion Way, Suite 200 Canonsburg, PA 15317 Matthew.Pistner@genon.com	724-597-8400

****** End of Report ******

STREAMLINED TITLE V PERMIT TERMS FOR SULFUR DIOXIDE EMISSIONS

Applicable SO_2 Emission Limitations: 25 Pa. Code § 123.22(a)(1)
SIP Approved SO_2 Limits
40 CFR § 52.2020

On March 5, 1996, the U. S. Environmental Protection Agency (EPA) issued guidance entitled, "White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program." Section II A of this guidance document allows state permitting authorities to streamline multiple applicable requirements on the same emissions units. Consequently, the Pennsylvania Department of Environmental Protection (PADEP) has determined that it is appropriate to streamline the sulfur oxides emission limits (expressed as SO_2) for combustion units in the Commonwealth's State Implementation Plan (SIP) and 25 Pa. Code § 123.22(a)(1). The current emissions limitation specified in the SIP is "4.0 pounds per million Btu of heat input *at any time*." The amended SO_2 limit currently codified in 25 Pa. Code § 123.22(a)(1) is "4.0 pounds per million Btu of heat input over *any 1-hour period*." The requirements of § 123.22(a)(1) are at least as stringent as the SO_2 emission limits set forth in 40 CFR § 52.2020.

In accordance with the guidance provided in EPA's White Paper #2, PADEP evaluated the monitoring, record keeping, testing, and reporting requirements applicable to the streamlined SO2 emission limitation. The Department has determined that the SIP approved limitation of "4.0 pounds per million Btu of heat input *at any time*," has no monitoring, record keeping or reporting requirements associated with the requirement. Any testing to demonstrate compliance with the SIP approved SO_2 limit would require The permittee to utilize EPA's Reference Method 6 which specifies that testing be conducted over a one hour period. A review of the applicable requirements for determining SO_2 emissions from sources subject to 25 Pa.Code § 122.22(a)(1) revealed that those sources must comply with the requirements in 25 Pa. Code § 139.13 and the test methods prescribed in 25 Pa.Code § 139.4(5).

For purpose of determining whether emissions of SO_2 from stationary sources are "4.0 pounds per million Btu of heat input over *any 1-hour period*," the test methods and procedures must be completed in accordance with the *Source Testing Manual* procedures specified in 25 Pa. Code § 139.4(5). *The testing procedures specified in* Chapter 5.0 (relating to sulfur compound testing) of this Manual states that "[s]sampling and analytical procedures should follow the provisions contained in EPA Method 6 with the exceptions that the glass wool and contents of the isopropanol midget bubbler are not discarded as specified in the method. The glass wool and the isopropanol solution must be analyzed for SO_3/SO_4 . The SO_3/SO_4 fraction is then added to the SO_2 fraction to produce the total oxides of sulfur, expressed as SO_2." Since the methodology in the *Source Testing Manual* also includes the SO_3/SO_4 fraction in the final results, the results would indicate a higher emission rate than using EPA's Method 6. Therefore, PADEP believes that the test method prescribed in 25 Pa.Code § 139.4(5) could demonstrate to EPA's satisfaction that compliance with 25 Pa.Code § 123.22(a)(1) would assure compliance with the current SIP provision which specifies "4.0 pounds per million Btu of heat input *at any time*."

The development of a compliance schedule is unnecessary because The permittee is also currently subject to the SO_2 emission limitations and applicable test methods specified in the Pennsylvania Code. Therefore, based on PADEP's findings, the SO_2 emission of "4.0 pounds per million Btu of heat input over *any 1-hour period* " in 25 Pa. Code § 123.22(a)(1) appear to be at least equivalent to, if not more stringent than the current SIP approved applicable requirement of "4.0 pounds/MMBtu at any time."

In accordance with EPA's White Paper #2, the SIP approved applicable requirement for the SO_2 emission limitation has been streamlined and subsumed in 25 Pa. Code § 123.22(a)(1). The Department believes that the test data will allow The permittee to certify that compliance with the streamlined SO_2 emission limitations assures compliance with the subsumed SIP approved emission limit of "4.0 pounds per million Btu of heat input *at any time.*"

Commonwealth of Pennsylvania
Department of Environmental Protection
Air Quality Program
Northcentral Region

PHASE II Acid Rain Permit
TIVOP #17-00001

Issued to: Shawville Generating Station
Operated by: RRI Energy Mid-Atlantic Power Holding, LLC
Bradford Township, Clearfield County
TIVOP# 17-00001
ORIS: 3131
Effective: January 1, 2008 through December 31, 2012

Acid Rain Permit Contents

1. *Statement of Basis*
2. *SO_2 Allowance Allocations and NO_x Requirements for Affected Units*
3. *Additional Permit Requirements (25 Pa. Code §127.531)*
4. *Permit Application (Attached)*

David W. Aldenderfer
Regional Air Program Manager
Northcentral Region

May 29, 2009
Date Issued

PHASE II Acid Rain Permit

Issued to: Shawville Generating Station
Operated by: RRI Energy Mid-Atlantic Power Holding, LLC
TIVOP# 17-00001
ORIS 3131
Effective: January 1, 2008 through December 31, 2012

Statement of Basis

Statutory and Regulatory Authority

In accordance with Section 6.5 of the Air Pollution Control Act, 35 P.S. § 4006.5, the Pennsylvania Department of Environmental Protection issues this permit pursuant to Pennsylvania Code Title 25 Chapter 127, Subchapter G, Section 127.531.

SO_2 Allowance Allocations and NO_x Requirements for Affected Units

Source ID #031 - Dry Bottom Wall Fire - BW - Unit - 1

Year:	*2008*	*2009*	*2010*	*2011*	*2012*
SO2 Allowances:	*4430*	*4430*	*4437*	*4437*	*4437*
NO_x Limit (lbs./MMBtu)	*Pursuant to 40 CFR Part 76, the Pennsylvania Department of Environmental Protection approves a NO_X emissions averaging plan for Unit 1, effective beginning 2008 through 2012. Under the NO_X compliance plan this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR Part 75, shall not exceed the alternative contemporaneous annual emission limitation (ACEL), as defined in 40 CFR Section 76.2, of* ***0.524 lb/MMBtu*** *for the dry bottom wall fired boiler. Additionally, under the NO_X compliance plan this unit's actual annual heat input for each year shall not exceed* ***6,840,000 MMBtu*** *for each year. Additionally, the permittee shall keep records to verify compliance with the ACEL and annual heat input limitations.* *Should any ACEL or heat input limitation, as specified in the application dated June 22, 2007, be exceeded during any year, the permittee shall submit a demonstration to the Department, by March 1 of the following year, that includes the information contained in 40 CFR Section 76.11(d)(1)(ii) to show compliance with the NO_X emissions averaging plan.* *In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.*				

Sean Wenrich
Acid Rain Permit Reviewer

Signature

May 29, 2009
Date

PHASE II Acid Rain Permit

Issued to: Shawville Generating Station
Operated by RRI Energy Mid-Atlantic Power Holding, LLC
TIVOP# 17-00001
ORIS 3131
Effective: January 1, 2008 through December 31, 2012

Source ID #032 - Dry Bottom Wall Fire - BW - Unit - 2

Year:	*2008*	*2009*	*2010*	*2011*	*2012*
SO2 Allowances:	*4456*	*4456*	*4463*	*4463*	*4463*
NO$_x$ Limit (lbs./MMBtu)	*Pursuant to 40 CFR Part 76, the Pennsylvania Department of Environmental Protection approves a NO$_X$ emissions averaging plan for Unit 2, effective beginning 2008 through 2012. Under the NO$_X$ compliance plan this unit's annual average NO$_x$ emission rate for each year, determined in accordance with 40 CFR Part 75, shall not exceed the alternative contemporaneous annual emission limitation (ACEL), as defined in 40 CFR Section 76.2, of* ***0.542 lb/MMBtu*** *for the dry bottom wall fired boiler. Additionally, under the NO$_X$ compliance plan this unit's actual annual heat input for each year shall not exceed* ***7,130,000 MMBtu*** *for each year. Additionally, the permittee shall keep records to verify compliance with the ACEL and annual heat input limitations.* *Should any ACEL or heat input limitation, as specified in the application dated June 22, 2007, be exceeded during any year, the permittee shall submit a demonstration to the Department, by March 1 of the following year, that includes the information contained in 40 CFR Section 76.11(d)(1)(ii) to show compliance with the NO$_X$ emissions averaging plan.* *In addition to the described NO$_X$ compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO$_x$ compliance plan and requirements covering excess emissions.*				

Sean Wenrich		May 29, 2009
Acid Rain Permit Reviewer	*Signature*	*Date*

PHASE II Acid Rain Permit

Issued to: Shawville Generating Station
Operated by RRI Energy Mid-Atlantic Power Holding, LLC
TIVOP# 17-00001
ORIS 3131
Effective: January 1, 2008 through December 31, 2012

Source ID #033 - Tangentially Fired Boiler - CE - Unit - 3

Year:	*2008*	*2009*	*2010*	*2011*	*2012*
SO2 Allowances:	*6111*	*6111*	*6122*	*6122*	*6122*
NO_x Limit (lbs./MMBtu)	*Pursuant to 40 CFR Part 76, the Pennsylvania Department of Environmental Protection approves a NO_X emissions averaging plan for Unit 3, effective beginning 2008 through 2012. Under the NO_X compliance plan this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR Part 75, shall not exceed the alternative contemporaneous annual emission limitation (ACEL), as defined in 40 CFR Section 76.2, of* ***0.45 lb/MMBtu*** *for the dry bottom wall fired boiler. Additionally, the permittee shall keep records to verify compliance with the ACEL limitation.* *Should any ACEL or heat input limitation, as specified in the application dated June 22, 2007, be exceeded during any year, the permittee shall submit a demonstration to the Department, by March 1 of the following year, that includes the information contained in 40 CFR Section 76.11(d)(1)(ii) to show compliance with the NO_X emissions averaging plan.* *In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.*				

Sean Wenrich
Acid Rain Permit Reviewer

Signature

May 29, 2009
Date

PHASE II Acid Rain Permit

Issued to: Shawville Generating Station
Operated by RRI Energy Mid-Atlantic Power Holding, LLC
TIVOP# 17-00001
ORIS 3131
Effective: January 1, 2008 through December 31, 2012

Source ID #034 - Tangentially Fired Boiler - CE - Unit - 4

Year:	*2008*	*2009*	*2010*	*2011*	*2012*
SO2 Allowances:	*6070*	*6070*	*6081*	*6081*	*6081*
NO_x Limit (lbs./MMBtu)	*Pursuant to 40 CFR Part 76, the Pennsylvania Department of Environmental Protection approves a NO_X emissions averaging plan for Unit 4, effective beginning 2008 through 2012. Under the NO_X compliance plan this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR Part 75, shall not exceed the alternative contemporaneous annual emission limitation (ACEL), as defined in 40 CFR Section 76.2, of **0.45 lb/MMBtu** for the dry bottom wall fired boiler. Additionally, the permittee shall keep records to verify compliance with the ACEL limitation.* *Should any ACEL or heat input limitation, as specified in the application dated June 22, 2007, be exceeded during any year, the permittee shall submit a demonstration to the Department, by March 1 of the following year, that includes the information contained in 40 CFR Section 76.11(d)(1)(ii) to show compliance with the NO_X emissions averaging plan.* *In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.*				

Sean Wenrich
Acid Rain Permit Reviewer

Signature

May 29, 2009
Date

PHASE II Acid Rain Permit

Issued to: Shawville Generating Station
Operated by RRI Energy Mid-Atlantic Power Holding, LLC
TIVOP# 17-00001
ORIS 3131
Effective: January 1, 2008 through December 31, 2012

Additional Permit Requirements:

1. *In accordance with 25 Pa. Code §127.531(d), the source is required to achieve compliance with this permit as soon as possible but no later than the date required by the Clean Air Act or the regulations thereunder for the source.*

2. *Pursuant to the Reasonably Available Control Technology (RACT) requirements of 25 Pa. Code Sections 129.91 through 129.95, the nitrogen oxides emissions (NOx, expressed as NO2) from the exhaust of each of the following units shall not exceed the respective following limitations based on a 30 day rolling average:*

   a) *Source ID 031 (Unit 1) - 0.524 pound per million BTU of heat input.*

   b) *Source ID 032 (Unit 2) - 0.542 pound per million BTU of heat input.*

   c) *Source ID 033 (Unit 3) - 0.45 pound per million BTU of heat input.*

   d) *Source ID 034 (Unit 4) - 0.45 pound per million BTU of heat input.*

3. *In accordance with 25 Pa. Code §127.531(f), this permit prohibits the following:*

   a) *Annual emissions of sulfur dioxide in excess of the number of allowances to emit sulfur dioxide that the owner or operator or designated representative holds for the unit.*

   b) *Exceeding applicable emission rates or standards, including ambient air quality standards.*

   c) *The use of an allowance prior to the year for which it is allocated.*

   d) *Contravention of other provisions of the permit.*

4. *In accordance with 25 Pa. Code §127.531(g), this permit prohibits the emission of sulfur dioxides (SO_x) and nitrogen oxides (NO_x) which exceeds any allowances that the source lawfully holds under Title IV of the Clean Air Act or the regulations thereunder*

   a) *A permit revision will not be required for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program, if the increases do not require a permit revision under another applicable requirement.*

   b) *A limit will not be placed on the number of allowances held by the source. The source may not, however, use allowances as a defense to noncompliance with another applicable requirement.*

   c) *An allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the Clean Air Act.*

5. *The source shall comply with all of the requirements in the attached Phase II Acid Rain Permit Application.*

Sean Wenrich
Acid Rain Permit Reviewer

Signature

May 29, 2009
Date

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5
77 WEST JACKSON BOULEVARD
CHICAGO, IL 60604-3590

APR 25 2012

REPLY TO THE ATTENTION OF:

Michael W. Ahern
Manager, Permit Issuance and Data Management Section
Ohio Environmental Protection Agency
Division of Air Pollution Control
50 West Town Street
Suite 700
P.O. Box 1049
Columbus, Ohio 43216

RE: Clarifications concerning federal enforceability of Ohio Administrative Code (OAC) rule 3745-15-07 nuisance permit term in Ohio OAC Chapter 3745-77 Title V permits.

Dear Mr. Ahern,

Thank you for your letter dated April 4, 2012, regarding the U.S. Environmental Protection Agency's position on the federal enforceability of Ohio's nuisance rule, OAC 3745-15-07, in Title V permits. Your letter specifically asks EPA to clarify whether, under Section 504(a) of the Clean Air Act (CAA) and 40 C.F.R. § 70.2, all provisions in State Implementation Plans (SIPs) are federally enforceable, or whether there have been any decisions or policy changes since 1999 that would lead EPA to have a different conclusion than that which was stated in the June 1999 letter from Steve Rothblatt to Bob Hodanbosi with respect to objecting to proposed Title V permits that identify Ohio's nuisance provisions as state-only enforceable.

Upon re-examining the underlying regulations, Section 504(a) of the CAA, and 40 C.F.R. § 70.2, we reaffirm our position that, because EPA has approved it into the Ohio SIP, OAC 3745-15-07 is a federally enforceable permit term for purposes of Title V permits. As noted above, you referenced in your letter a June 1999 letter from Steve Rothblatt to Bob Hodanbosi. In Enclosure A to that letter, EPA explained stated that "all provisions contained in an EPA-approved SIP and all terms and conditions in SIP-approved permits are ... federally enforceable.... [A]ll such terms and conditions are also federally enforceable 'applicable requirements' that must be incorporated into the Federal side of a Title V permit." Thus, if nuisance provisions apply to a stationary source either because it is subject to the provisions in the Ohio SIP or because a permit issued pursuant to a SIP-approved program contains the requirements, the terms must be included in the federally enforceable side of the source's Title V permit.

Your letter also asked about any decisions or policy changes since 1999 that would lead EPA to have a different conclusion. EPA has not issued any guidance that would contradict this outcome.

We look forward to continuing to work with you on this issue. If you have any questions or wish to discuss this issue further, please feel free to contact me or Charmagne Ackerman, of my staff, at (312) 886-0448.

Sincerely,

Genevieve Damico

Genevieve Damico
Chief
Air Permits Section

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5
77 WEST JACKSON BOULEVARD
CHICAGO, IL 60604-3590

APR 20 2011

REPLY TO THE ATTENTION OF:

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Howard Chapman Jr., President
H. Kramer & Co.
1345 West 21st Street
Chicago, Illinois 60608

Re: Notice of Violation
H. Kramer & Co.
Chicago, Illinois

Dear Mr. Chapman:

The U.S. Environmental Protection Agency is issuing the enclosed Notice of Violation (NOV) to H. Kramer & Co. (Kramer). The NOV is being issued under Section 113(a)(1) of the Clean Air Act, 42 U.S.C. § 7413(a)(1). We find that you are in violation of the Clean Air Act, 42 U.S.C. §§ 7401 *et seq.*, and the Illinois State Implementation Plan, at your Chicago, Illinois facility.

Section 113 of the Clean Air Act gives us several enforcement options. These options include issuing an administrative compliance order, issuing an administrative penalty order, and bringing a judicial civil or criminal action.

We are offering you an opportunity to confer with us about the violations alleged in the NOV. The conference will give you the opportunity to present information on the specific findings of violation, the efforts you have taken to comply, and the steps you will take to prevent future violations.

Please plan for your facility's technical and management personnel to attend the conference to discuss compliance measures and commitments. You may have an attorney represent you at this conference.

The technical contacts in this matter are Kushal Som and Dakota Prentice. You may call either Kushal Som at (312) 353-5792 or Dakota Prentice at (312) 886-6761 to request a conference. You should make the request as soon as possible, but no later than 10 calendar days after you receive this letter. We should hold any conference within 30 calendar days of your receipt of this letter.

Sincerely,

Cheryl L. Newton
Director
Air and Radiation Division

Enclosure

cc: Ray Pilapil, Manager
Compliance and Systems Management Section
Illinois Environmental Protection Agency

Todd R. Wiener
McDermott Will & Emery LLP

United States Environmental Protection Agency
Region 5

IN THE MATTER OF:) **NOTICE OF VIOLATION**
)
H. Kramer & Co.) **EPA-5-11-IL-11**
Chicago, Illinois)
)
)
Proceedings Pursuant to Section 113(a)(1))
of the Clean Air Act,)
42 U.S.C. § 7413(a)(1))

NOTICE OF VIOLATION

The U. S. Environmental Protection Agency (EPA) is issuing this Notice of Violation under Section 113(a)(1) of the Clean Air Act (CAA), 42 U.S.C. § 7413(a)(1). EPA finds that H. Kramer & Co. (Kramer) in Chicago, Illinois, is in violation of the CAA, 42 U.S.C. §§ 7401 *et seq.*, and the Illinois State Implementation Plan (SIP) as follows:

Statutory and Regulatory Authority

1. The CAA, 42 U.S.C §§ 7401, *et seq.*, and the regulations promulgated thereunder, establish a statutory and regulatory scheme designed to protect and enhance the quality of the nation's air so as to promote the public health and welfare and the productive capacity of its population.

National Ambient Air Quality Standards

2. Pursuant to Sections 108 and 109 of the CAA, 42 U.S.C. §§ 7408 and 7409, EPA revised the National Ambient Air Quality Standards (NAAQS) for lead on November 12, 2008. 73 Fed. Reg. 67052 (2008). The revised national primary and secondary ambient air quality standards for lead and its compounds are 0.15 micrograms per cubic meter ($\mu g/m^3$), arithmetic mean concentration over a 3-month period. *See* 40 C.F.R. § 50.16. EPA revised the primary NAAQS for lead to provide increased protection for children and other at-risk populations against an array of adverse health effects, most notably including neurological effects in children. EPA revised the secondary standard to be identical to the revised primary standard.

Illinois SIP

3. On May 31, 1972, EPA approved Illinois Pollution Control Board (IPCB) Rules 101 and 102 as part of the federally enforceable SIP for the State of Illinois. 37 Fed. Reg. 10842. IPCB Rule 101 has been recodified at 35 Illinois Administrative Code (Ill. Admin. Code) § 201.102. IPCB Rule 102 has been recodified at 35 Ill. Admin. Code § 201.141.

4. The Illinois SIP at 35 Ill. Admin. Code § 201.141 provides, in pertinent part, that no person shall cause or threaten or allow the discharge or emission of any contaminant into the environment in any State so as, either alone or in combination with contaminants from other sources, to cause or tend to cause air pollution in Illinois or so as to prevent the attainment or maintenance of any applicable ambient air quality standard.

5. The Illinois SIP at 35 Ill. Admin. Code § 201.102 defines "Ambient Air Quality Standard" as those standards promulgated from time to time by the IPCB or by the EPA.

6. The Illinois SIP at 35 Ill. Admin. Code § 201.102 defines "Air Pollution" as the presence in the atmosphere of one or more air contaminants in sufficient quantities and of such characteristics and duration as to be injurious to human, plant, or animal life, to health, or to property, or to unreasonably interfere with the enjoyment of life or property.

Factual Background

7. Kramer owns and operates a secondary copper smelting facility located at 1345 West 21st Street in Chicago, Illinois (the Facility). The Facility includes one 35 ton rotary furnace (Rotary Furnace #1), one 60 ton rotary furnace (Rotary Furnace #2), three coreless electric induction furnaces, and two channel furnaces.

8. Rotary Furnace #1 and Rotary Furnace #2 produce the copper alloys, brass and bronze ingots.

9. The two rotary furnaces, three electric induction furnaces, and two channel furnaces are emission sources. Emissions from these furnaces include lead.

10. To control air pollution emissions, Kramer operates five baghouses of varying capacity for the two rotary furnaces (Baghouse Nos. 1, 2, 5, and 6) and three electric induction furnaces (Baghouse No. 4). The emissions from the two channel furnaces are controlled by a venturi scrubber and mist eliminator, in series.

11. To determine compliance with the revised NAAQS for lead, the Illinois Environmental Protection Agency, with assistance from EPA, placed an air monitor on the roof of the Perez Elementary School located at 1241 West 19th Street in Chicago, Illinois. The location was chosen to monitor and capture metals emitted from the Facility.

12. Based on a three month rolling average from October through December of 2010, EPA determined that the revised NAAQS for lead had been exceeded at the air monitor located at the Perez Elementary School. The three month rolling average lead concentration at the monitor was 0.241 $\mu g/m^3$.

13. Based on a three month rolling average from November 2010 through January 2011, EPA determined that the revised NAAQS for lead had been exceeded at the air monitor located at the Perez Elementary School. The three month rolling average lead concentration at the monitor was 0.294 $\mu g/m^3$.

14. The highest concentrations of lead from October 2010 through January 2011 occurred when there was a southerly/southwesterly wind direction (as recorded at the nearest meteorological station in Alsip, Illinois). The Kramer Facility is located southwest of the air monitor.

Violations

15. Kramer caused or allowed the emission of lead into the air so as, either alone or in combination with contaminants from other sources, to cause air pollution in Illinois and /or to prevent the attainment or maintenance of the revised NAAQS for lead in violation of the Illinois SIP at 35 Ill. Admin. Code § 201.141.

4/20/11
Date

Cheryl L. Newton
Cheryl L. Newton
Director
Air and Radiation Division

CERTIFICATE OF MAILING

I, Betty Williams, do hereby certify that a Notice of Violation of the Clean Air Act was sent by Certified Mail, Return Receipt Requested, to:

Howard Chapman Jr., President
H. Kramer & Co.
1345 West 21st Street
Chicago, Illinois 60608

I also certify that I sent copies of the NOV by first class mail to:

Ray Pilapil, Manager
Bureau of Air
Compliance and Enforcement Section
Illinois Environmental Protection Agency
1021 North Grand Avenue East
Springfield, Illinois 62702

Todd R. Wiener, Esq.
McDermott Will & Emery LLP
227 West Monroe Street
Chicago, Illinois 60606

on the 20th day of April, 2011.

Betty Williams
Betty Williams, Secretary
AECAS (IL/IN)

CERTIFIED MAIL RECEIPT NUMBER: 7009 1680 0000 7670 2508

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NORTHCENTRAL REGIONAL OFFICE

March 26, 2012

Mr. Zachery Fabish
Project Attorney
The Sierra Club
408 C Street NE
Washington, DC 20002

Re: Renewal Title V Operating Permit 17-00001

Dear Mr. Fabish:

Enclosed please find a copy of Title V Operating Permit 17-00001 (renewal). Pursuant to 25 Pa Code Chapter 127, after consideration of all comments received and revisions to the proposed operating permit, the Title V operating permit complies with all Federal and State regulatory requirements including the requirements from 40 CFR § 70.6(c)(1) which requires monitoring in accordance with 40 CFR Part 64 for particulate matter emissions from Shawville's electric generating units. Therefore, the Department decided to issue Title V Operating Permit 17-00001 to GenOn REMA, LLC for their Shawville facility. The official issuance date of this Title V permit is March 26, 2012. Title V Operating Permit 17-00001 (renewal) became effective on March 26 2012 and will expire on March 25, 2017. Please include the following identification number with any correspondence to the Department concerning this Title V operating permit: 17-00001.

Additionally, the Title V operating permit addresses the comments that the Sierra Club submitted on the Department's notice of intent to issue published in the November 20, 2010 *Pennsylvania Bulletin*. The comment period for the November 20, 2010 notice was extended until January 4, 2011 to afford the Sierra Club an opportunity to submit comments on the notice. The Department received Sierra Club's comments via letters dated January 4, 2011, and supplemental comments via correspondence dated September 22, 2011. A summary of the applicable Title V operating permit requirements for periodic monitoring of particulate matter is provided in the information below. Additionally, this letter contains the Department's item-by-item response to the Sierra Club's comments on the Department's November 20, 2010 notice on Title V Operating Permit 17-00001 as they were presented in the Sierra Club's January 4, 2011 and September 22, 2011 correspondence.

1. *Comment:* The draft permit lacks adequate periodic monitoring regarding the plant's particulate matter emissions.

The Department agrees and disagrees with the commenter. First, the commenter confuses the applicability of the regulations in 25 Pa. Code §§123.11(3) and 139.12(4). Each of the cited regulations is an independently applicable requirement and must be included in the Title V operating permit, as appropriate. However, the commenter is incorrect as to the basic purpose and authority of 25 Pa. Code §139. Whenever a facility is required to perform source testing, e.g. through the requirements of any order, plan approval or other permit, such testing must performed using the methods in 25 Pa. Code §139. When stack testing is conducted, the facility must, at a minimum, take a sample every hour. However, the commenter has assumed that if an hourly sample is required during stack testing, then the standard for which compliance is being evaluated must also be applied as an hourly average. This assumption is incorrect. By this reasoning, if a facility that is subject to a daily average or other longer term limit, either through the SIP or a federal standard, and it is required to use a continuous emissions monitor to determine compliance, the averaging period for determining compliance would presumptively become the sampling frequency of the CEMS. This would obviously lead to an absurd result since the performance specification for the CEMS could require, for example, that sampling occur every 15 minutes.

The authority of 25 Pa. Code §139, which is to establish source testing requirements, is clearly outlined in 25 Pa. Code, Article III, Air Resources. In 25 Pa. Code §139.3, General Requirements, section (a) states that "The Department will use the methods set forth in this chapter to assess emissions from stationary sources..." Similarly, the requirement specified in 25 Pa. Code §139.11 states that "The following provisions are applicable to source tests for determining emissions from stationary sources..." And most tellingly, for particulate matter, §139.12(1) states that "[t]ests for determining emissions of particulate matter from stationary sources shall conform with the following..." Nowhere in the regulation is there a suggestion that source testing requirements amend, revise, or change an emissions standard.

The Department agrees with the commenter that the Title V operating permit must include monitoring requirements sufficient to assure compliance with the permit terms and conditions. However, the Department disagrees that the monitoring in the proposed Title V operating permit fails to meet the commenter's standard that "...monitoring must assure *continuous* compliance where emission limits have instantaneous parameters". In determining whether the permit has included "adequate periodic monitoring", the commenter has failed to consider all of the monitoring requirements in the permit. An emissions limit that must be met at all times does not necessarily require that *emissions* be monitored continuously. In fact, that would be technically impossible even with a CEMS.

In 40 CFR Part 64, EPA has established regulations for enhanced monitoring that relies primarily on parametric monitoring, i.e. monitoring that relies on a surrogate for direct emissions. The Department has determined that the Shawville plant is subject to Part 64 and is required to submit and comply with a compliance assurance monitoring plan (CAM). The Title V operating permit reflects requirements from GenON's CAM plan and includes additional periodic monitoring to assure compliance with 40 CFR Part 64. Additionally, the CAM requirements were revised and now are similar to the proposed protocol, "*Compliance Assurance Monitoring (CAM) Protocol for an Electrostatic Precipitator (ESP) for Controlling Particulate Matter (PM) Emissions from a Coal-Fired Boiler*" which was published by EPA for CAM guidance. In the proposed guidance, a computer model uses ESP parameter monitoring and stack testing data to evaluate ESP performance. Similarly, the CAM requirements for Shawville use COMS and stack testing data to predict the particulate matter emission rate every hour of operation. The

CAM monitoring requirements are established to reasonably assure compliance with the particulate matter emission limitation of 25 Pa. Code §123.11 in accordance with the requirements of 40 CFR Part 64. Furthermore, since the continuous opacity monitoring system (COMS) at the Shawville plant is required to meet Pennsylvania's plan for opacity monitoring requirements, which is approved by EPA to meet the requirements of 40 CFR 51.214, the COMS satisfy the general criteria of 40 CFR §§64.3(a) and (b) pursuant to 40 CFR §64.3(d)(2). Taken together, the CAM monitoring requirements and periodic particulate matter testing provide adequate periodic monitoring for the particulate matter standard in §123.11(3).

2. *Comment.* The draft permit includes inadequate compliance assurance monitoring requirements regarding Shawville's particulate matter.

The commenter provides specific examples as to how the monitoring in the permit is inadequate to assure compliance.

The commenter states that the draft permit improperly relies on opacity monitoring as the method to ensure continuous compliance with the particulate matter limits because opacity monitoring fails to "adequately capture secondary particulate matter emissions". The Department disagrees with this comment. Although the definition of "particulate matter" in 25 Pa. Code §121 includes both the solid and liquid fractions, compliance with the standard in 25 Pa. Code §123.11(3) is to be determined according to 25 Pa. Code §139.12. The latter clearly states that the test method for particulate matter shall include only dry filters and does not require testing for condensable particulate matter emissions. On its face, the definition of particulate matter and the standard in 25 Pa. Code §123.11(3) would appear to be in conflict. However, the particulate matter standard in 25 Pa. Code §123.11(3) was adopted in September 1971, with the last revision occurring in 1972. At that time the emission standard was intended to be an indicator and protective of the National Ambient Air Quality Standard (NAAQS) for total suspended particulate. Compliance with the TSP NAAQS, and the limits adopted to implement the TSP NAAQS, were based on Method 5 testing, i.e. total filterable particulate matter. The indicators for NAAQS have evolved to include both the filterable and condensable components of PM-10 and PM-2.5. However, the emission standard in 25 Pa. Code §123.11(3) has not evolved and remains a TSP-based emissions standard. The merits of opacity monitoring as an indicator of condensable emissions, is, therefore, moot.

The commenter states that the draft permit should include, at the very least, quarterly stack tests for condensable particulate matter. The Department disagrees with this comment for the reasons stated above.

The commenter states that continuous emissions monitoring systems for fine particles (as PM-2.5) and for particulate matter in general should be required in the permit. As justification for this claim, the commenter lists facilities that have been required to install particulate matter CEMS, they describe the health concerns associated with particulate matter, particularly PM-10 and PM-2.5, and note that PM CEMS are widely available. Finally, the commenter concludes that "...because it is the only technology that "provides a reasonable assurance of ongoing compliance with emission limitations or standards" per 40 CFR §64.3(a)(2), it must be implemented...". The Department does not question the information provided by the commenter. However, the commenter referred to a requirement in 40 CFR §64.3(a)(2) as justification for requiring installation and operation of PM CEMS. This is contradictory to the requirements of 40 CFR Part 64. 40 CFR Part 64 does not apply to units that have a CEMS (see 40 CFR §60.2(b)(vi)), and by its very existence, the requirements of 40 CFR Part 64 acknowledges something other than CEMS can, in fact, provide a reasonable assurance of ongoing compliance when the monitoring system complies with 40 CFR Part 64. 40 CFR §64.3(a)(1) states that to provide a reasonable assurance of compliance, the owner or operator shall "...design the monitoring to obtain data on one or more indicators of emission control performance...Indicators of performance may include ...direct or predicted emissions (including visible emissions or opacity), process and control device parameters ... or recorded findings of inspection and maintenance activities..."

The commenter states that the permit must have provisions that tie specific opacity levels to particulate matter levels so that violations of opacity standards can readily be translated to violation of the correlating particulate matter standards. The Department disagrees with this comment. 40 CFR §64.3(d) outlines special criteria for the use of COMS and other continuous monitoring methods. Specifically, COMS that satisfies at least one of the requirements listed in 40 CFR§§64.3(d)(2)(i) through (vi) shall be deemed acceptable and satisfies the general design criteria in sections (a) and (b) of 40 CFR §64.3. The COMS at the Shawville facility meet the requirements of 40 CFR §51.214 and therefore, meet the design criteria under CAM. With respect to indicator ranges, §64.3(d)(2) states that a COMS may be subject to the criteria for establishing indicator ranges. In determining whether indicator ranges in this case are necessary, the preamble to CAM rule describes the general approach to CAM. The Department has reviewed the preamble to the CAM rule and included a CAM indicators and a CAM indicator range in the Title V operating permit to predict particulate matter emissions from the Shawville facility.

The Title V operating permit includes the applicable CAM requirements, including a CAM indicator parameter and a CAM indicator parameter range pursuant to 40 CFR §§64.3(d)(3)(ii) and 64.6(c)(1)(i), respectively. The Title V operating permit also identifies an excursion for the units at Shawville which covers the permit requirements of 40 CFR §64.6(c)(2). Additionally, the excursion reporting conditions in the Title V operating permit satisfy the requirements of 40 CFR §64.3(d)(3)(i). The Title V operating permit requires all CAM indicators to be measured at least every 15 minutes to satisfy the requirements in 40 CFR §64.3(b)(4)(ii). Therefore, the performance requirements established in 40 CFR §64.6(c)(1)(iii) are satisfied. The Title V operating permit also incorporated the operational requirements when an excursion is detected by reference. The operational requirements are codified in 40 CFR §64.7 and included in the Title V operating permit.

An important aspect of the operational requirements of 40 CFR §64.7 is to assure that the control measures are properly operated and maintained so that they do not deteriorate to the point where the owner or operator fails to remain in compliance with applicable requirements. There are two basic approaches to assuring that control measures taken by the owner or operator to achieve compliance are properly operated and maintained so that the owner or operator continues to achieve compliance with applicable requirements. The first approach comes from monitoring the operation of the control device (e.g. electrostatic precipitator) in accordance with applicable monitoring requirements from an applicable regulatory standard (e.g. NSPS, NESHAP, CAM, etc.). The second approach, as applicable when there is no periodic monitoring in the underlying standard, adds periodic monitoring, sufficient to yield reliable data from the relevant time period that are representative of the source's compliance. However, the second approach is not applicable to Shawville's electric generating units since the first approach is applicable and requires the Department to add periodic monitoring in accordance with the CAM provisions. These approaches are finalized in the "Final Rule Interpreting the Scope of Certain Monitoring Requirements for State and Federal Operating Permits Programs." (71 FR 38147, July 5, 2006) which provides an interpretation by rule for the requirements of 40 CFR § 70.6(c)(1). In addition to the CAM monitoring requirements, the Title V operating permit includes testing, recordkeeping and compliance certification reporting to satisfy the permit requirements specified in 40 CFR § 70.6(c)(1).

The acceptable approach to cover the monitoring of particulate matter emissions from the Shawville facility until compliance with the Mercury and Air Toxics Rule is shown: (1) Documents continued operation of the control measures within ranges of specified indicators of performance (such as emissions, control device parameters and process parameters) that are designed to provide a reasonable assurance of compliance with applicable requirements; (2) indicating any excursions from these ranges; and (3) responding to the data so that excursions are corrected. As outlined in the preamble to the CAM rule, the requirements of 40 CFR Part 64 adopts this approach as an appropriate approach to enhance monitoring in the context of Title V permitting for significant emission units that use control devices to achieve compliance with emission limits. (62 FR 54902, October 22, 1997).

3. *Comment.* The draft permit lacks a compliance schedule for remedying significant, ongoing violations of the Clean Air Act.

The Department disagrees with this comment. The opacity violations reported in the first and second quarter of 2008 (Exhibit 7) were resolved by the Department and the company through the consent assessment of civil penalty that the Sierra Club submitted as Exhibit 10. Therefore, the Department does not have any ongoing violations related to opacity at the Shawville plant. The 2010 second quarter CEMS report submitted as Exhibit 11 in the Sierra Club's comment, which had shown three (3) emission violation days for Units 3 and 4, did not result in any enforcement action as identified on the respective CEMS report. The report was prepared in accordance with the Department's Continuous Source Monitoring Manual by the Department's Continuous Source Monitoring group. Based on the information to date, the Department has no knowledge of any enforcement action that resulted from the notice of violation (NOV) issued by Region 3. Therefore, there is no need or requirement to include a compliance schedule into the Title V operating permit.

4. *Comment.* The draft permit fails to ensure that the Shawville Plant will not cause or contribute to violations of the new one-hour NAAQS for SO2.

The Department disagrees with these comments and notes that the commenter does not specify what is meant by "include the new … NAAQS in the provisions that preclude the plant from causing or contributing to ambient air quality exceedances". Pennsylvania's regulations at 25

Pa. Code §121.1 define the term "applicable requirements" for Title V facilities and 25 Pa. Code §127.502(a) states that "[f]or Title V facilities, the applicable requirements for stationary air contamination sources in the Title V facility shall be included in the operating permit". Nowhere in the definition of "applicable requirement" or in the regulations outlining what must be in the Title V permit, is there a suggestion that a Title V permit must include provisions that would preclude the plant from causing or contributing to a violation of the NAAQS. Until there is an underlying applicable requirement expressly addressing the NAAQS, such as a SIP provision or a federal standard, there is no applicable requirement to preclude the Title V facility from causing ambient air quality exceedances.

5. *Comment.* The draft permit fails to ensure that the Shawville Plant will not cause or contribute to violations of the new one-hour NAAQS for NO2.

See response to item 4 above.

6. *Comment.* The draft permit does not provide sufficient specificity in its requirements for continuous emissions monitoring for SO2, CO2 and NOx.

The Department agrees with this comment. The data collection provisions of 40 CFR §75.10 have been included by reference in the Title V operating permit requirements (see Section D, Source IDs 031 through 034).

The supplemental comments are addressed above within the responses to the accepted comments submitted on January 4, 2011. In lieu of the fact that the supplemental comments were submitted after the expiration of the comment period, the Department has referenced the location of its response to the comments submitted on September 22, 2011 regarding draft Title V operating permit.

Please see below the Department's item-by-item response to the draft Title V operating permit comments as they were presented in the Sierra Club's September 22, 2011 letter.

1. Comment. PaDEP must timely ensure Shawville's Compliance with the 1-hour SO2 NAAQS

The Department plans on submitting revisions to Pennsylvania's SIP for compliance with the 1-hour SO2 to EPA prior to the 2014 deadline.

Response to the comment relating to the Draft Permit Would Allow Shawville to Cause Extreme Nonattainment Over a Vast Area

The Department disagrees with the comment based on the information above.

Response to comment relating to the Clean Air Act and Pennsylvania's SIP Require That Any Title V Permit for the Shawville Plant Ensure Compliance with the 1-Hour SO2 NAAQS.

The Department disagrees with the comment based on the information above.

Response to comment relating to Pennsylvania Law Additionally Requires Compliance with the 1-Hour SO2 NAAQS

The Department disagrees with the comment based on the information above.

Response to comment relating to Action on Shawville's Title V Permit Renewal Is Long Overdue.

The Department has acted on GenON Shawville's Title V Operating Permit Renewal.

The Department appreciates your efforts to preserve and protect our environment and the residents of our Commonwealth. I hope the above information addresses your concerns. If you have any additional concerns or any questions regarding the terms and conditions of renewal Title V Operating Permit 17-00001, please contact me at 570-327-3648.

Sincerely,

Muhammad Q. Zaman

Muhammad Q. Zaman
Environmental Program Manager
Air Quality Program

Enclosure

cc: File
EPA, Region 3
Central Office, Air Quality Permits

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF:	)	
	)	ORDER RESPONDING TO
UNITED STATES STEEL	)	PETITIONER'S
CORPORATION – GRANITE CITY	)	REQUEST THAT THE
WORKS	)	ADMINISTRATOR
	)	OBJECT TO ISSUANCE OF STATE
CAAPP No. 96030056	)	OPERATING PERMIT
Proposed by the Illinois	)	
Environmental Protection Agency	)	Petition Number V-2009-03
	)	

ORDER GRANTING IN PART AND DENYING IN PART PETITION FOR OBJECTION TO PERMIT

INTRODUCTION

On September 3, 2009, pursuant to its authority under the Illinois Clean Air Act Permitting Program (CAAPP), the Illinois Environmental Protection Act, 415 ILCS 5/39.5, title V of the Clean Air Act (Act), 42 U.S.C. §§ 7661-7661f, and the United States Environmental Protection Agency's (EPA) implementing regulations in 40 C.F.R. part 70 (part 70), the Illinois Environmental Protection Agency (IEPA) issued a title V operating permit to United States Steel Corporation – Granite City Works (USS). USS is an integrated steel manufacturing facility that involves raw material processing/preparation, coke production, coke oven gas by-products recovery plant, iron production, steel production, and steel finishing.

On October 1, 2009, the Interdisciplinary Environmental Clinic at the Washington University School of Law submitted to EPA on behalf of the American Bottom Conservancy (Petitioner) a petition requesting that EPA object to the USS title V permit pursuant to section 505(b)(2) of the Act, 42 U.S.C. § 7661d(b)(2), and 40 C.F.R. § 70.8(d). Petitioner alleges that (1) the permit fails to include all applicable permits and permit requirements; (2) the permit fails to provide periodic monitoring sufficient to assure compliance; (3) the permit lacks compliance schedules to remedy all current violations; (4) the permit unlawfully exempts emissions during startup, shutdown, and malfunctions (SSM); (5) the permit fails to include compliance assurance monitoring (CAM) requirements; and (6) numerous permit provisions are not practically enforceable.

EPA has reviewed Petitioner's allegations pursuant to the standard set forth in section 505(b)(2) of the Act, 42 U.S.C. § 7661d(b)(2), which requires the Administrator to issue an objection if the petitioner demonstrates to the Administrator that the permit is not in compliance with the applicable requirements of the Act. *See also* 40 C.F.R. § 70.8(d); *New York Public Interest Research Group* v. *Whitman*, 321 F.3d 316, 333, n. 11 (2d Cir. 2003).

Based on a review of the available information, including the petition, the permit record, and relevant statutory and regulatory authorities and guidance, I grant Petitioner's request in part and deny it in part, for the reasons set forth in this Order.

STATUTORY AND REGULATORY FRAMEWORK

Section 502(d)(1) of the Act, 42 U.S.C. § 7661a(d)(1), requires each state to develop and submit to EPA an operating permit program to meet the requirements of title V. EPA granted final full approval of the Illinois title V operating permit program effective November 30, 2001. 66 Fed. Reg. 62946 (December 4, 2001).

All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emission limitations and other conditions necessary to assure compliance with applicable requirements of the Act, including the requirements of the applicable State Implementation Plan (SIP). *See* sections 502(a) and 504(a) of the Act, 42 U.S.C. §§ 7661a(a) and 7661c(a). The title V operating permit program generally does not impose new substantive air quality control requirements (referred to as "applicable requirements"), but does require that permits contain monitoring, recordkeeping, reporting, and other requirements sufficient to assure compliance with applicable requirements. 57 Fed. Reg. 32250, 32251 (July 21, 1992). One purpose of the title V program is to "enable the source, States, EPA, and the public to understand better the requirements to which the source is subject, and whether the source is meeting those requirements." *Id.* Thus, the title V operating permit program is a vehicle for ensuring that air quality control requirements are appropriately applied to facility emission units and for assuring compliance with such requirements.

Under section 505(a) of the Act, 42 U.S.C. § 7661d(a), and the relevant implementing regulations at 40 C.F.R. § 70.8(a), states are required to submit each proposed title V operating permit to EPA for review. Upon receipt of a proposed permit, EPA has 45 days to object to final issuance of the permit if EPA determines the permit is not in compliance with applicable requirements or the requirements of part 70. 40 C.F.R. § 70.8(c). Section 505(b)(2) of the Act provides that, if EPA does not object to a permit on its own initiative, any person may petition the Administrator, within 60 days of expiration of EPA's 45-day review period, to object to the permit. 42 U.S.C. § 7661d(b)(2); *see also* 40 C.F.R. § 70.8(d). The petition must "be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting agency (unless the petitioner demonstrates in the petition to the Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period)." 42 U.S.C. § 7661d(b)(2). In response to such a petition, the Administrator must issue an objection if a petitioner demonstrates that a permit is not in compliance with the requirements of the Act. *Id.; see also* 40 C.F.R. § 70.8(c)(1); *New York Public Interest Research Group, Inc.* v. *Whitman,* 321 F.3d at 333, n. ll. Under section 505(b)(2) of the Act, 42 U.S.C. § 7661d(b)(2), the burden is on the petitioner to make the required demonstration to EPA. *Sierra Club* v. *Johnson,* 541 F.3d 1257, 1266-1267 (11th Cir. 2008); *Citizens Against Ruining the Environment* v. *EPA,* 535 F.3d 670, 677-678 (7th Cir. 2008); *Sierra Club* v. *EPA,* 557 F.3d 401, 406 (6th Cir. 2009); *McClarence* v. *EPA,* 596 F.3d 1123, 130-31 (9th Cir. 2010) (discussing the burden of proof in title V petitions). If, in responding to a petition, EPA objects to a permit that has already been issued, EPA or the permitting authority will modify, terminate, or revoke and reissue the permit consistent with the procedures set forth in 40 C.F.R. §§ 70.7(g)(4), (5)(i) - (ii) and 70.8(d).

BACKGROUND

USS first applied in March 1996 for a CAAPP title V permit. IEPA determined in May 1996 that the application was complete and published a draft permit for public comment in 2003. USS submitted a supplemental permit application in 2007 to address maximum achievable control technology (MACT) standards. IEPA considered this application a supplement to the 1996 application and, therefore, did not perform a second completeness determination. IEPA issued a new draft CAAPP permit and Project Summary (IEPA's Statement of Basis) for public comment in October 2008. IEPA held a public hearing regarding the new draft permit on December 2, 2008, and provided follow-up answers in January 2009 to questions it could not answer at the time of the hearing. Subsequently, on February 27, 2009, Petitioner submitted written comments on the draft permit to IEPA. EPA received the proposed permit for its 45-day review on June 19, 2009. EPA did not object to the permit, and IEPA issued the final CAAPP permit for the facility, along with a response to public comments, on September 3, 2009.

Under the statutory timeframe in section 505(b)(2) of the Act, 42 U.S.C. § 7661d(b)(2), October 2, 2009, was the deadline to file a petition requesting that EPA object to the final USS permit. Petitioner submitted its petition to EPA on October 1, 2009. Accordingly, EPA finds that Petitioner timely filed its petition.

ISSUES RAISED BY THE PETITIONER

I. The Permit Fails to Include All Applicable Permits and Permit Requirements

Petitioner's Allegations:

Petitioner alleges that IEPA did not include all applicable requirements in the USS title V permit. Petition at 6-9. Specifically, Petitioner points to the emission reduction credits in the IEPA-issued construction permits[1] for cogeneration and the coke plant/coke conveyance system projects[2] (coke plant project permits) that were under construction at the time Petitioner submitted its petition. Petitioner claims that the requirements contained in the permits are applicable requirements, as that term is defined at 415 ILCS 5/39.5(1) and 40 C.F.R. § 70.2,

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[1] Petitioner refers to the following four IEPA-issued new source review permits:
Permit No. 06070022 – Emission Reduction Credits Permit issued January 18, 2007;
Permit No. 06070023 – Cogeneration Project Permit issued January 30, 2008;
Permit No. 06070088 – Coke Conveyance System Permit issued March 13, 2008; and
Permit No. 06070020 – Coke Plant Permit issued March 13, 2008 to Gateway Energy &Coke Company, c/o SunCoke Company.

[2] One of the four permits to which Petitioner cites, Permit No. 06070020, was issued to SunCoke Company. However, in Permit No. 06070020 and in Permit No. 06070088, issued to USS for construction of a coke conveyance system, IEPA noted that the two modifications are considered a single project for purposes of new source review applicability. *See* Permits No. 06070020 and No. 06070088, both at 4.

because IEPA issued the permits pursuant to the State's SIP-approved new source review (NSR) program for major sources and the delegated prevention of significant deterioration (PSD) program. *Id.* at 6-7. Petitioner asserts that the coke plant project constitutes a major source of particulate matter of 2.5 microns or less ($PM_{2.5}$) in a $PM_{2.5}$ nonattainment area, and thus could not proceed without "offsets" of other $PM_{2.5}$ emissions from USS. Petitioner claims that the coke plant project permits reference the IEPA-issued emission reduction credit permit because it provided some of the necessary offsets. *Id.* at 7. Petitioner further claims that, because the provisions of the cogeneration project and coke plant project permits that enabled the project to avoid major NSR are minor source permit requirements, they also must be included in the USS title V permit. *Id.* at 7-8. Petitioner asserts that both the cogeneration and coke plant projects under construction at the time Petitioner submitted the petition rely on netting to avoid major NSR permit requirements. Petitioner alleges that, for a source to rely on netting to avoid permit requirements, it must be bound legally to undertake the emission reductions before it commences construction. *Id.* at 8.

EPA Response:

A title V permit must include all applicable requirements. *See* 40 C.F.R. §§ 70.5(c)(4) and 70.6(a)(1). The term "applicable requirement," as defined in 40 C.F.R. § 70.2 and Illinois' CAAPP regulations, includes "any term or condition of any preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C or D, of the Act." In addition, both part 70 and Illinois' CAAPP regulations include in the definition of "applicable requirement" those requirements that will become effective during the term of the title V permit. *See* 40 C.F.R. §§ 70.2, 70.5(c)(4) and (8), and 415 ILCS 5/39.5. In its Responsiveness Summary on this issue, IEPA stated that the "CAAPP permit for U.S. Steel reflects only current operations. [Both the cogeneration and coke plant projects] permitted through construction permits [cited by Petitioner in its comments] are under construction and not operable yet." Responsiveness Summary at 24-25. IEPA did not provide any legal justification for its position that the permit only needed to reflect current operations, nor did it dispute that the PSD permits contained applicable requirements. The facilities that are the subject of the more recently issued NSR permits are [considered by IEPA to be] part of the source that is covered by the title V operating permit under review in this action. Thus by failing to include the provisions of the NSR permits in the title V permit, IEPA has acted contrary to both part 70 and Illinois' CAAPP regulations that define the term "applicable requirement."[3] Based on EPA's and

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[3] In stating that the USS CAAPP permit reflects current operations and that sources covered by the preconstruction permits were still under construction, it is possible that IEPA was intending to refer to 40 C.F.R. §70.5(a)(1)(ii). That provision states in relevant part: "Part 70 sources required . . . to have a permit under the preconstruction review program approved into the applicable implementation plan under part C or D of title I of the Act [i.e., the New Source Review program], shall file a complete application to obtain the part 70 permit or permit revision within 12 months after commencing operation or on or before such earlier date as the permitting authority may establish. Where an existing part 70 permit would prohibit such construction or change in operation, the source must obtain a permit revision before commencing operation."

EPA's proposed part 70 rule stated that any source required to have a preconstruction permit under the NSR program would be subject to the part 70 program, but the proposed rule did not address the timing of a title V application. *See* 57 Fed. Reg. 32250, 32271. EPA included 40 C.F.R. 70.5(a)(1)(ii) in the final rule to address this issue and situations where a source had no title V permit or such permit was not up for revision, or where the

Illinois' definition of "applicable requirement," as described above, the emission reduction credits and all other terms of the construction permits issued pursuant to SIP-approved programs are applicable requirements and, as such, must be included in the title V operating permit. I therefore grant the petition on this issue, and direct IEPA to include the requirements for the emission reduction credits in the USS CAAPP permit, as well as all other requirements of the pre-construction permits cited by Petitioner at pages 6 and 9 of the petition.[4] *See In the Matter of Wisconsin Public Service Corporation's JP Pulliam Power Plant,* Petition Number V-2009-01 (June 28, 2010) at 3-5.

II. The Permit Fails to Provide Periodic Monitoring Sufficient to Assure Compliance

Petitioner's Allegations:

Petitioner claims that the USS CAAPP permit does not meet the periodic monitoring requirements of part 70 for various requirements applicable to the coal handling operations, the coke production operations, the coke oven gas by-products recovery plant, the blast furnaces, the basic oxygen furnaces, the continuous casting operations, the hot strip mills, the finishing operations, the boilers, the internal combustion engines, and the gasoline storage and dispensing operations. Petition at 9-28. Petitioner claims that permitting authorities must take the following three steps to satisfy the monitoring requirements of title V:

1. Under 40 C.F.R. § 70.6(a)(3)(i)(A), where existing regulations or underlying permits prescribe monitoring that is appropriate to the timeframe of the emission

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source's existing permit would prohibit construction or a change in operation. As EPA explained in the final rule, a source must submit a title V application generally within 12 months after the date on which the source becomes subject to the title V program. *Id.* at 32272. The Act implies that a source becomes subject to the title V program when operations commence. *Id.* Therefore, a source that receives a preconstruction permit and will be newly subject to title V generally would have 12 months after commencing operation to submit a title V application. 40 C.F.R. § 70.5(a)(1)(ii) follows this reading of the statute, and it "prevents the source from being subject to an enforcement action during the 12-month period that it operates before it applies for an operating permit." *Id.* This rule also addresses when an existing title V source would need to apply for a title V permit revision, and provides that (except in situations where the part 70 permit would prohibit such construction or change in operation) the source must submit its application within 12 months of commencing operations. *Cf.* 40 C.F.R. § 70.7(f)(1)(i).

Importantly, 40 C.F.R. § 70.5(a)(1)(ii) does not provide an exception to the definition of "applicable requirement." Nor is it an exemption from the Act's requirement that all title V permits include conditions to assure compliance with all "applicable requirements . . . including the requirements of the applicable implementation plan." *See* 42 U.S.C. § 7661b. 40 C.F.R. § 70.5(a)(1)(ii) does not apply in a situation where a permitting authority is issuing a title V permit to a source and the source holds preconstruction permits that have been issued. The preconstruction permits are applicable requirements, as noted above, and nothing in the Act or the regulations allows a permitting authority to exclude them from the title V permit.

[4] Petitioner suggests that the terms of the preconstruction permits would not be federally enforceable until they were incorporated into USS's title V permit. *See* Petition at p. 8. EPA disagrees with this assertion. EPA has the authority to enforce preconstruction permits issued pursuant to delegated PSD programs or to SIP-approved major and minor NSR programs regardless of whether they are incorporated into title V permits. *See* Section 113(a)(1) and (a)(3) of the Act, 42 U.S.C. § 7413(a)(1) and (a)(3).

limit and sufficient to assure compliance, the permitting authority must properly incorporate that monitoring requirement into the title V permit.

2. Under 40 C.F.R. § 70.6(a)(3)(i)(B), where there is no previously-established monitoring requirement to correspond to an emission limit, the permitting authority must add "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit."

3. Under 40 C.F.R. § 70.6(c)(1), where there exists a previously-established monitoring requirement corresponding to an emission limit, but that monitoring is not sufficient to assure compliance with limit, the permitting authority must supplement monitoring to assure such compliance.

Petition at 9, citing *Sierra Club v. EPA*, 536 F.3d 673 (D.C. Cir. 2008), *CITGO Refining and Chemicals Company L.P.*, Petition No. VI-2007-01 (May 28, 2009) at 7 and *Premcor Refining Group, Inc.*, Petition No. VI-2007-02) at 7 (May 28, 2009). Petitioner asserts that the United States Court of Appeals for the District of Columbia Circuit made clear in *Sierra Club* that the Act requires augmentation of monitoring requirements where requirements exist but are not adequate to ensure compliance, (Petition at 10, quoting *Sierra Club*, 536 F.3d at 678) and that the Illinois Environmental Protection Act also mandates supplemental monitoring where necessary to ensure compliance. *Id.*, quoting 415 ILCS 5/39.5(7)(b).

Petitioner asserts that the USS CAAPP permit contains numerous conditions that establish emission limits but lack periodic monitoring requirements sufficient to assure compliance with the limits. *Id.* Petitioner also asserts that the Project Summary contains conclusory statements about the monitoring requirements but no justifications for IEPA's monitoring choices, and that IEPA must satisfy the monitoring requirements and provide a rationale for the monitoring, as required by part 70. *Id.* at 11-12. Finally, Petitioner alleges that IEPA failed to respond to its significant comments regarding the adequacy of monitoring in the USS CAAPP permit. *Id.* at 11-12.

EPA Response:

EPA's part 70 monitoring rules (40 C.F.R. § 70.6(a)(3)(i)(A) and (B) and 70.6(c)(1)) are designed to address the statutory requirement that "[e]ach permit issued under [title V] shall set forth . . . monitoring . . . requirements to assure compliance with the permit terms and conditions." 42 U.S.C. § 7661c(c). As a general matter, permitting authorities must take three steps to satisfy the monitoring requirements in EPA's part 70 regulations. First, under 40 C.F.R. § 70.6(a)(3)(i)(A), permitting authorities must ensure that monitoring requirements contained in applicable requirements are properly incorporated into the title V permit. Second, if the applicable requirement contains no periodic monitoring, permitting authorities must add "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." 40 C.F.R. § 70.6(a)(3)(i)(B). Third, if there is some periodic monitoring in the applicable requirement, but that monitoring is not sufficient to assure compliance with permit terms and conditions, permitting authorities must supplement monitoring to assure such compliance. 40 C.F.R. § 70.6(c)(1). *See CITGO* at 6-7.

In addition to meeting these three steps, the rationale for the monitoring requirements selected by a permitting authority must be clear and documented in the permit record (e.g., in the statement of basis). 40 C.F.R. § 70.7(a)(5). The determination of whether monitoring is adequate in a particular circumstance generally is a context-specific determination. The monitoring analysis should begin by assessing whether the monitoring required in the applicable requirement is sufficient to assure compliance with permit terms and conditions. Some factors that permitting authorities may consider in determining appropriate monitoring are: (1) the variability of emissions from the unit in question; (2) the likelihood of a violation of the requirements; (3) whether add-on controls are being used for the unit to meet the emission limit; (4) the type of monitoring, process, maintenance, or control equipment data already available for the emission unit; and (5) the type and frequency of the monitoring requirements for similar emission units at other facilities. The preceding list of factors provides the permitting authority with a starting point for its analysis of the adequacy of the monitoring; the permitting authority also may consider other site-specific factors. *CITGO* at 7-8.

Further, IEPA has an obligation to respond adequately to significant comments on the draft title V permit. Section 502(b)(6) of the Act, 42 U.S.C. § 7661a(b)(6), requires that all title V permit programs include adequate procedures for public notice regarding the issuance of title V operating permits, "including offering an opportunity for public comment." *See* 40 C.F.R. § 70.7(h). It is a general principle of administrative law that an inherent component of any meaningful notice and opportunity for comment is a response by the regulatory authority to significant comments. *Home Box Office v. FCC*, 567 F.2d 9, 35 (D.C. Cir. 1977) ("the opportunity to comment is meaningless unless the agency responds to significant points raised by the public."). *See, also, In the Matter of Louisiana Pacific Corporation*, Petition Number V-2006-3 (Nov. 5, 2007), at 4-5.

The petition sets out approximately 50 instances in the USS title V permit where Petitioner claims IEPA has failed to include sufficient monitoring to assure compliance and/or where IEPA has failed to justify the required monitoring. These issues are addressed below. In sum, in the instances described below where I grant on the monitoring issues raised by Petitioner, IEPA must ensure it has: (1) satisfied the monitoring requirements of 40 C.F.R. § 70.6(a)(3)(i)(A) and (B) and (c)(1); (2) provided a rationale for the monitoring requirements placed in the permit (*see* 40 C.F.R. § 70.7(a)(5)); and (3) responded to significant comments. *CITGO* at 8.

A. Coal Handling Operations

Petitioner's Allegations:

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with the emission limit for particulate matter of 10 microns or less (PM_{10}) found in Condition 7.1.3(f) of the permit. Petition at 12. Petitioner states that the permit only requires inspections of control equipment and related recordkeeping but does not require any actual monitoring. Petitioner concludes that, because USS must meet the emission limit for PM_{10} on an hourly basis, the permit must be revised to require additional periodic monitoring, such as a continuous emission monitoring system (CEMS) for particulate matter (PM), to assure compliance with the limit. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA claims that the "[r]ecordkeeping requirements of Conditions 7.1.10(b), (d), 5.9.3(d) and inspection requirements of Condition 7.1.8 are sufficient to satisfy requirements of 39.5(7)(d) of the Act and ensure that control device is operated properly." Responsiveness Summary at 27. IEPA's response simply recites the monitoring requirements. IEPA did not provide a sufficient analysis to demonstrate how the monitoring requirements in the USS permit assure compliance with the terms and conditions of the permit, or yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comment.[5] IEPA's response to Petitioner's comment was silent on how Conditions 7.1.10(b) and (d), 5.9.3(d) and the inspection requirements of Condition 7.1.8 are sufficient to assure compliance with the related emissions requirements. Therefore, I grant the petition on this issue.

Petitioner also argues that CEMS should be considered the means to comply with the periodic monitoring requirements of part 70. Although CEMs may be the preferred type of monitoring in some instances, they are not always necessary to assure compliance with applicable requirements. Section 504(b) of the Act, 42 U.S.C. § 7661c(b), provides that "continuous emissions monitoring need not be required if alternative methods are available that provide sufficiently reliable and timely information for determining compliance." *See also, In the Matter of Alliant Energy WPL - Edgewater Generating Station*, Petition Number V -2009-02 (August 17, 2010), at 11.

Petitioner has neither identified an applicable requirement that compels the use of CEMS nor demonstrated that a CEM is the only monitoring that can assure compliance with this particular emission limit. I am ordering IEPA either to explain how the USS permit provides adequate monitoring or to modify the permit to ensure that it contains monitoring sufficient to

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[5] As discussed above, if the applicable requirement contains no periodic monitoring, the permitting authority must add periodic monitoring to the title V permit "sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." 40 C.F.R. § 70.6(a)(3)(i)(B). If the applicable requirement contains some periodic monitoring, but that monitoring is not sufficient to assure compliance with permit terms and conditions, permitting authorities must, "[c]onsistent with paragraph (a)(3) . . . ," add monitoring "sufficient to assure compliance with the terms and conditions of the permit." 40 C.F.R. § 70.6(c)(1). Both of these monitoring rules (40 C.F.R. §§ 70.6(a)(3)(i)(A) and (B) and 70.6(c)(1)) are designed to address the statutory requirement that "[e]ach permit issued under [title V] shall set forth . . . monitoring . . . requirements to assure compliance with the permit terms and conditions." CAA section 504(c). Thus, in evaluating whether the permit contains monitoring sufficient to assure compliance under 40 CFR 70.6(c)(1), EPA believes it is appropriate to consider whether such monitoring is "sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit."

assure compliance with the terms and conditions of the permit. Therefore, I deny the claim seeking an order that IEPA must require the use of CEMS in the USS CAAPP permit.

B.1. Coke Production - Coke Oven Charging, Leaks from Doors, Leaks from Lids, and Leaks from Offtakes

Petitioner's Allegations:

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with visible emission (VE) limits found in Conditions 7.2.3-1(a) and (c), 7.2.3-2(a) and (b), 7.2.3-3(a) and (b), and 7.2.3-4(a) and (b) of the permit. Petition at 12. Petitioner states that the VE limits are based on state regulations and a state-issued permit for Coke Oven Battery B. *Id.* Petitioner further claims that Condition 7.2.14 provides monitoring methods, but does not require the permittee to monitor for compliance with the VE limits. *Id.* Petitioner notes that IEPA states in its Responsiveness Summary that "daily testing of visual emissions are required by condition 7.2.7-3(a) pursuant to 40 C.F.R. part 63, Subpart L," (sic), but claims that, because the emission limits are not based on and are not equivalent to the limits in the federal MACT regulations, IEPA's statement is unclear. *Id.*, quoting Responsiveness Summary at 27.

EPA Response:

IEPA did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the VE limits, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its response to Petitioner's comments. In any case, as noted above, part 70 requires an analysis in the statement of basis or permit record of how the monitoring is sufficient to assure compliance with permit terms and conditions, or sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit, including any augmentation of monitoring requirements where the state has found that monitoring in applicable requirements is not adequate to assure compliance. 40 CFR § 70.6(a)(3)(i)(B), 70.6(c)(1) and 70.7(a)(5). IEPA's response to Petitioner's comment simply recited the monitoring requirements in the permit and was silent on how the monitoring requirements of 40 C.F.R. part 63, subpart L are related to the emissions requirements in the permit. Therefore, I grant the petition on this issue.

B.2. Coke Production - Combustion (Battery) Stack

Petitioner's Allegations:

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with the PM emission limits found in Condition 7.2.3-7(a)(i) and (c) of the permit. Petition at 13. Petitioner asserts in both instances that the permit requires a single performance test one year before the renewal date of the permit, even though the PM limits require continuous compliance. *Id.* Petitioner claims that IEPA states in the Responsiveness Summary that "CEMs are generally not required for periodic monitoring." *Id.*, quoting Responsiveness Summary at 26-27. Petitioner claims IEPA's response did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the terms and conditions of the permit. Furthermore, Petitioner alleges that PM CEMs should be required because they are both available and feasible. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "Condition 7.2.7(d) of the final CAAPP addresses testing requirements for coke oven combustion stacks." Responsiveness Summary at 27. IEPA's response simply recites the monitoring requirements in the permit. IEPA did not provide in its response an analysis to demonstrate how the monitoring requirements in Condition 7.2.7(d) of the USS permit are sufficient to assure compliance with the terms and conditions of the permit or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit. Therefore, I grant the petition on this issue.

Petitioner also asserts that CEMS be considered the means to comply with the periodic monitoring requirements of Part 70. As noted above, although CEMs may be the preferred type of monitoring in some instances, they are not always necessary to assure compliance with permit terms and conditions. Section 504(b) of the Act provides that "continuous emissions monitoring need not be required if alternative methods are available that provide sufficiently reliable and timely information for determining compliance." 42 U.S.C. § 7661c(b). *See also, In the Matter of Alliant Energy WPL - Edgewater Generating Station*, Petition Number V -2009-02) (August 17, 2010), at 11.

Petitioner has neither identified an applicable requirement that compels the use of CEMS nor demonstrated that a CEMS is the only monitoring that can assure compliance with the applicable requirements. I am ordering IEPA either to explain how the USS permit provides adequate monitoring or to modify the permit to ensure that it contains monitoring sufficient to assure compliance with the associated permit terms and conditions. Therefore, I deny the claim seeking an order that IEPA must require the use of CEMS in the USS CAAPP permit.

B.3. Coke Production - Bypass/Bleeder Stack Flare

Petitioner's Allegations:

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with the VE limit found in Condition 7.2.3-8(b) of the permit. Petition at 14. Petitioner claims that, although the permit references the federal MACT regulation that specifies monitoring for visible emissions from flares, the permit does not expressly require USS to monitor flare emissions to assure compliance with the limit. *Id.* Petitioner argues that IEPA's statement in the Responsiveness Summary, that "40 CFR 63.309(h) does not specify the frequency of no visible emissions observations," is inadequate. *Id.*, quoting Responsiveness Summary at 27. Petitioner concludes by asserting that IEPA is required to add periodic monitoring requirements to the permit or provide additional information to justify the monitoring required in the permit. *Id.* at 14.

EPA Response:

IEPA did not explain how the monitoring requirements in the USS permit are sufficient to assure compliance with the associated permit terms and conditions. The fact that 40 C.F.R. § 63.309(h) does not specify a monitoring frequency does not end the analysis. As the permitting authority, IEPA must determine whether the monitoring included in a regulation is sufficient to assure compliance with the permit terms and conditions. If it is not, the permitting authority must supplement the monitoring. Therefore, I grant the petition on this issue.

C. Coke Oven Gas By-Products Recovery Plant

Petitioner's Allegations:

Petitioner alleges that the permit's annual opacity reading requirement for the coke oven by-products flare is not frequent enough to assure compliance with the VE limit found in Condition 7.3.10(a)(i) of the permit. Petition at 14. Petitioner asserts that daily or more frequent monitoring such as the use of video monitoring is reasonable to assure compliance with visible emission limits for flares. *Id.* Petitioner further claims that IEPA's rationale for the monitoring associated with condition 7.3.10(a)(i) is unclear. *Id.* Petitioner notes that IEPA stated in its Responsiveness Summary that "[f]laring events are not frequent due to the use of this material as a fuel." *Id.*, quoting Responsiveness Summary at 28. Petitioner concludes that, to assure that monitoring requirements are sufficient, IEPA must clearly explain the frequency and duration of flaring events, and must provide additional information to justify the monitoring requirements associated with Condition 7.3.10(a)(i).

EPA Response:

In its Responsiveness Summary, IEPA states that "[r]egular monthly ignition system inspections… would assure that flare system operates properly. Video monitoring of flare is not needed due to established testing provisions of Condition 7.3.8(c)(vi), inspection requirements of Condition 7.3.9 and the recordkeeping requirements of Condition 7.3.11(c)(iv)(D)." Responsiveness Summary at 28. While IEPA addressed why it thought video monitoring is not needed, IEPA's response did not provide an analysis to demonstrate how the annual opacity reading or the monthly ignition system inspections are sufficient to assure compliance with the no visible emission limit or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit. IEPA refers to the frequency of flaring events but does not provide any support for this and how it justifies an annual reading. Therefore, I grant the petition on this issue.

D.1. Blast Furnace - Control Equipment

Petitioner's Allegations:

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with the PM emission limit found in Condition 7.4.3-1(a)(ii)(A) of the permit. Petition at 15. Petitioner asserts that a one-time performance test during the permit term (once every 5 years) does not constitute periodic monitoring. *Id.* Petitioner further asserts that IEPA's rationale for the monitoring requirements associated with Condition 7.4.3-1(a)(ii)(A) is inadequate. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "the monitoring and testing procedures outlined in Subsection 7.4 of the final CAAPP and the MACT standard are sufficient enough to demonstrate continuous compliance with the applicable emission standards." Responsiveness Summary at 29. IEPA's response recites the monitoring requirements and asserts that they are sufficient. IEPA's response does not provide an analysis to demonstrate how a performance test once every 5 years as required in the USS permit is sufficient to assure compliance with the terms and conditions of the permit, or is sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's allegations. Therefore, I grant the petition on this issue.

D.2. Blast Furnaces – Opacity

Petitioner's Allegations:

Petitioner alleges that the weekly opacity readings required in the permit are not sufficient to assure compliance with the visible emission limit found in Condition 7.4.3-1(d)(ii) of the permit. Petitioner also states that IEPA's response confuses matters as it refers to once-a-permit-term monitoring based on a MACT standard. Petitioner requests daily or more frequent opacity monitoring, including the use of video monitoring. Petition at 15.

EPA Response:

In addition to Condition 7.4.7-2(b)(i)(C)(1), which requires weekly opacity observations, IEPA refers in its Responsiveness Summary to once-a-permit-term monitoring in Condition 7.4.7-2(a)(ii). "[40 C.F.R. §] 63.7821(c) requires that '…For each emission unit equipped with a baghouse, you must conduct subsequent performance tests no less frequently than once during each term of your title V operating permit.' Therefore, Condition 7.4.7-2(a)(ii) of the final CAAPP correctly identifies frequency of subsequent testing. The IEPA believes that the monitoring and testing procedures outlined in Subsection 7.4 of the final CAAPP and the MACT standard are sufficient enough to demonstrate continuous compliance with the applicable emission standards." Responsiveness Summary at 29. EPA agrees it is unclear what monitoring requirements apply for purposes of the visible emission limit. Moreover, IEPA's response simply recites the monitoring requirements and concludes that they are sufficient. IEPA's response did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the terms and conditions of the permit or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. Therefore, I grant the petition on this issue.

D.3 Blast Furnace - Excess Gas Flare

Petitioner's Allegations:

Petitioner alleges that the annual opacity observations and monthly inspections of the flare ignition system required in the permit are not sufficient to assure compliance with the no visible emission limit found in Condition 7.4.5-4(e) of the permit, which applies on a continuous basis. Petitioner requests daily or more frequent monitoring, including the use of video monitoring. Petition at 15-16.

EPA Response:

In its Responsiveness Summary, IEPA states that "Condition 7.4.7-1 of the final CAAPP establishes monthly inspection requirements of the flare's ignition system. Condition 7.4.7-2(c) of the final CAAPP requires annual observations of a flare by using USEPA Method 22. Video monitoring of flare is not needed due to the inspection and testing requirements referenced above." Responsiveness Summary at 28. IEPA's response simply recites the monitoring requirements, but does not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the terms and conditions of the permit, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. Therefore, I grant the petition on this issue.

D.4 Blast Furnaces – Production and Emission Limits

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with the emission limits in Conditions 7.4.6(b)-(g) for the blast furnaces and related operations. Petitioner alleges that compliance with these conditions is demonstrated through the use of iron production records and emission factors established in PSD permit 95010001. Petition at 16. Petitioner alleges that neither the title V nor the PSD permit identifies the source of the emission factors. Further, Petitioner asserts that neither the Project Summary nor the Responsiveness Summary provides evidence that the emissions factors are representative of the emissions at the USS facility. *Id.* Petitioner concludes that IEPA must provide additional information about the source of the data used to calculate the emission factors and must clearly explain how the use of the emission factors is sufficient to assure compliance with the associated emission limits. *Id.* at 17. Petitioner makes additional specific allegations for each emission limit in the sections below.

a. Casthouse Baghouse (Furnace Tapping) Captured Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} emission limit found in Condition 7.4.6(b) of the permit as it relies on an emission factor from an unspecified source. *Id.* Petitioner further disagrees with IEPA's explanation that, in addition to the use of emission factors, testing requirements based on federal MACT regulations will be used to assure compliance with the PM_{10} emission limit in Condition 7.4.6(b), stating that the testing requirements are based on federal MACT regulations which do not apply to this permit condition. *Id.* Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "The IEPA believes that the monitoring and testing procedures outlined in Subsection 7.4 of the final CAAPP and the MACT standard are sufficient enough to demonstrate continuous compliance with the applicable emission standards." Responsiveness Summary at 29. IEPA did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the PM_{10} emission limits, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its response to Petitioner's comments. IEPA's response to Petitioner's comment simply recited the monitoring requirements in the permit and was silent on how the monitoring requirements of the MACT are related to the emissions requirements in the permit.

The record for the USS permitting action does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. With a few exceptions, EPA does not recommend the use of emission factors to develop source-specific permit limits or to determine compliance with permit requirements. *In the Matter of Tesoro Refining and Marketing Co, Martinez, California Facility,* Petition Number IX-2004-6 (March 15, 2005) at 32. I grant the petition on the monitoring issues related to such use of emission factors. IEPA either must justify in the record why these emission factors are representative of USS's operations (i.e., representative to yield reliable data from the relevant time period representative of the sources compliance), and provide sufficient evidence to demonstrate that the emissions will not vary by a degree that would cause an exceedance of the standards, or IEPA must determine and adequately support another mechanism to assure compliance with the applicable emission limits from the underlying construction permit. Furthermore, if IEPA can adequately justify the use of emission factors as a compliance mechanism, it also should require USS to confirm the appropriateness of the emission factors such as through the use of stack testing using EPA-approved methods on a periodic basis, as operations and equipment change or deteriorate over time.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the sulfur dioxide (SO_2) emission limit found in Condition 7.4.6(b) of the permit as it relies on an emission factor from an unspecified source. Petition at 17. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA refers to the monitoring for a different unit, the iron spout baghouse. Responsiveness Summary at 29. The record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the nitrogen oxides (NO_x) emission limit found in Condition 7.4.6(b) of the permit as it relies on an emission factor from an unspecified source. Petition at 18. According to Petitioner, IEPA has not provided further information on the "initial testing data" referenced in the Responsiveness Summary, making it difficult to determine whether testing is representative of NO_x emissions from the casthouse baghouse. Petitioner asserts that a margin of compliance is not a sufficient basis for a determination that emissions will not change over the life of the permit. *Id.* Petitioner further claims that IEPA's rationale for the monitoring requirements associated with the NO_x emission limit in Condition 7.4.6(b) is far too general. Petitioner concludes that IEPA must provide additional information to justify this monitoring condition or must revise the permit to require additional periodic monitoring. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states "The initial testing data indicates the actual level of NOx emissions from casthouse baghouse is almost three times lower than the allowable levels established in this condition. Therefore, application of CEMS is unnecessary. The IEPA believes that the monitoring and testing procedures outlined in Subsection 7.4 of the final CAAPP and the MACT standard are sufficient enough to demonstrate continuous compliance with the applicable emission standards." Responsiveness Summary at 30. EPA agrees that the record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue. Absent appropriate permit conditions limiting operations and inputs, initial testing data cannot be assumed to reflect the potential for variability in emissions. Operating conditions may change and a margin of compliance alone is not a sufficient safeguard in light of this potential for variability in operations and inputs, and consequently, emissions.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the volatile organic material (VOM) emission limit found in Condition 7.4.6(b) of the permit as it relies on an emission factor from an unspecified source. Petition at 18. According to Petitioner, IEPA has not provided further information on the "initial testing data" referenced, making it difficult to determine whether testing is representative of VOM emissions under maximum operating conditions of the blast furnaces. Petitioner asserts that a margin of compliance alone is not a sufficient basis to determine that emissions will not change over the life of the permit. *Id.* Petitioner concludes that IEPA must provide additional information to justify this monitoring condition or must revise the permit to require additional periodic monitoring. *Id.* at 18-19.

EPA Response:

In its Responsiveness Summary, IEPA states that "The initial testing data indicates the actual level of VOM emissions from casthouse baghouse is eight times lower than the allowable levels established in this condition. Because of such large margin of compliance, the IEPA does not support suggestions of VOM annual tests." Responsiveness Summary at 30. EPA agrees that the record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

b. Blast Furnace Uncaptured Fugitive Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the SO_2 emission limit found in Condition 7.4.6(c) of the permit as it relies on an emission factor from an unspecified source. Petition at 19. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states "condition 7.4.7-2(b)(i) of the final CAAPP establishes weekly visual observations of fugitive emissions released from the casthouse and supported by appropriate recordkeeping." Responsiveness Summary at 30. Condition 7.4.7-2(b)(i) of the final CAAPP refers to opacity testing. IEPA's response did not provide an analysis to demonstrate how the opacity monitoring requirements in the USS permit are sufficient to assure compliance with the uncaptured SO_2 emissions, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the NO_x emission limit found in Condition 7.4.6(c) of the permit as it relies on an emission factor from an unspecified source. Petition at 19. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states "condition 7.4.7-2(b)(i) of the final CAAPP establishes weekly visual observations of fugitive emissions released from the casthouse and supported by appropriate recordkeeping." Responsiveness Summary at 31. Condition 7.4.7-2(b)(i) of the final CAAPP refers to opacity testing. IEPA's response did not provide an analysis to demonstrate how the opacity monitoring requirements in the USS permit are sufficient to assure compliance with the uncaptured NO_x emissions, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the VOM emission limit found in Condition 7.4.6(c) of the permit as it relies on an emission factor from an unspecified source. Petition at 19. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states "condition 7.4.7-2(b)(i) of the final CAAPP establishes weekly visual observations of fugitive emissions released from the casthouse and supported by appropriate recordkeeping." Responsiveness Summary at 31. Condition 7.4.7-2(b)(i) of the final CAAPP refers to opacity testing. IEPA's response did not provide an analysis to demonstrate how the opacity monitoring requirements in the USS permit are sufficient to assure compliance with the uncaptured VOM emissions, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

c. Blast Furnace Charging Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} emission limit found in Condition 7.4.6(d) of the permit as it relies on an emission factor from an unspecified source. Petition at 19. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "Condition 7.4.11(f) of the final CAAPP does require [USS] to keep records of iron pellets charged to Blast Furnace. These records in conjunction with established emission factors are sufficient to establish actual emissions and to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act. Also, iron pellet charging does not have individual emission stack and that makes testing impossible." Responsiveness Summary at 32. EPA agrees that IEPA's response did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the terms and conditions of the permit, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

d. Slag Pits Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} emission limit found in Condition 7.4.6(e) of the permit as it relies on an emission factor from an unspecified source. Petition at 20. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "Condition 7.4.11(g) of the final CAAPP does require [USS] to keep records of slag processed. These records in conjunction with established emission factors are sufficient to establish actual emissions and to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the [Illinois Environmental Protection] Act. Also, slag pits do not have emission stack and that makes testing impossible." Responsiveness Summary at 32. EPA agrees that IEPA's response did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the terms and conditions of the permit, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the SO_2 emission limit found in Condition 7.4.6(e) of the permit as it relies on an emission factor from an unspecified source. Petition at 20. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states "condition 7.4.7-2(b)(i) of the final CAAPP establishes weekly visual observations of fugitive emissions released from the casthouse and supported by appropriate recordkeeping." Responsiveness Summary at 31. Condition 7.4.7-2(b)(i) of the final CAAPP refers to opacity testing for the casthouse. Neither IEPA's Project Summary nor its response to Petitioner's comments provided an analysis to demonstrate how the opacity monitoring requirements in the USS permit are sufficient to assure compliance with the uncaptured SO_2 emissions for the slag pits, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

e. Iron Spout Baghouse Captured Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} emission limit found in Condition 7.4.6(f) of the permit as it relies on an emission factor from an unspecified source. Petition at 20. Petitioner also claims that the Responsiveness Summary is confusing regarding this monitoring requirement because it suggests that testing requirements from federal MACT requirements will be used to assure compliance with the PM_{10} emissions limit in Condition 7.4.6(e). *Id.* Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that the "Condition 7.4.9(a)(ii) of the final CAAPP clearly identifies that each baghouse is equipped with a bag leak detection system. IEPA believes that the monitoring and testing procedures outlined in Subsection 7.4 of the final CAAPP and the MACT standard are sufficient enough to demonstrate continuous compliance with the applicable emission standards." Responsiveness Summary at 32. IEPA did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the PM_{10} emissions limits, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its response to Petitioner's comments. IEPA's response to Petitioner's comment simply recited the monitoring requirements in the permit and was silent on how the monitoring requirements of the MACT are related to the emissions requirements in the permit.

Further, the permitting record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility.

IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the SO_2 emission limit found in Condition 7.4.6(f) of the permit as it relies on an emission factor from an unspecified source. Petition at 20. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.* at 20-21.

EPA Response:

In its Responsiveness Summary, IEPA refers to the monitoring for a different unit, the casthouse baghouse. *See* Responsiveness Summary at 31. IEPA's response did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the terms and conditions of the permit, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

f. Iron Pellet Screen Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} emission limit found in Condition 7.4.6(g) of the permit as it relies on an emission factor from an unspecified source. Petition at 21. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "Condition 7.4.11(h) of the final CAAPP does require [USS] to keep records of iron pellets screened. These records in conjunction with the established emission factors are sufficient to establish actual emissions and to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act. Also, pellet screening does not have individual emission stack and that makes testing impossible." Responsiveness Summary at 33. EPA agrees that IEPA's response did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the terms and conditions of the permit, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

E.1. Basic Oxygen Furnaces (BOF) – Opacity

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the frequency of the monitoring requirements for the opacity limit found in Condition 7.5.3-1(c)(iv) of the permit. Condition 7.5.3-1(c)(iv) sets an opacity limit of 20 percent based on 3 minute averages for any secondary emissions that exit any opening in the basic oxygen process furnace (BOPF) shop or any other building housing the BOPF or BOPF shop operation. Condition 7.5.7-2(d) requires weekly opacity observations for uncaptured roof monitor emissions unless a previous observation measures opacity of 20 percent or more. If a previous observation measures opacity of 20 percent or more, daily monitoring is required until five consecutive observations are less than 20 percent. Petition at 21. Petitioner alleges that daily observations using EPA Method 9 are supported by EPA's April 18, 1997, *Region 7 Policy on Periodic Monitoring for Opacity* (Region 7 guidance) for title V permits, and that the permit must be revised to require at least daily opacity observations to assure compliance with the limit. Petitioner asserts that IEPA must provide additional information to justify the monitoring frequency given in the permit.

EPA Response:

In its Responsiveness Summary, IEPA states that "Condition 7.5.7-2(d) of the final CAAPP identifies frequency (weekly and daily) of roof monitor opacity visual observations." Responsiveness Summary at 37. EPA agrees that IEPA's response did not provide an analysis to demonstrate how the frequency of the monitoring requirements in the USS permit is sufficient to assure compliance with the terms and conditions of the permit, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. Therefore, I grant the petition on this issue. However, I note that the Region 7 guidance, which recommends daily observations for opacity monitoring, provides guidance to permitting authorities, but does not contain any requirements; therefore, IEPA does not have to use the monitoring methods discussed in the Region 7 guidance. Regardless of the monitoring method it includes in the USS permit, IEPA must fully explain the bases for and sufficiency of its choice of monitoring.

Petitioner's Allegations:

Petitioner alleges that the permit lacks periodic monitoring requirements sufficient to assure compliance with the opacity limit found in Condition 7.5.3-1(f) of the permit. Petition at 21. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "MACT presented in Subpart FFFFF does not require visual observation frequencies other than those established in the permit. Condition 7.5.7-1(c)(1) of the final CAAPP identifies frequency (weekly) of opacity readings from BOF shop openings. This is sufficient to yield compliance with Condition7.5.3-1(f)." Responsiveness Summary at 37. IEPA did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the visible emissions limit in 7.5.3-1(f), or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its response to Petitioner's comments. IEPA's response to Petitioner's comment simply recited the monitoring requirements in the permit and was silent on how the monitoring requirements of 40 C.F.R. part 63, subpart FFFFF are related to the emissions requirements in the permit. Therefore, I grant the petition on this issue.

E.2. Basic Oxygen Furnaces – Production and Emission Limits

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with the emission limits in conditions 7.5.6(c)-(i) for the basic oxygen furnaces and related operations. Petition at 22. Petitioner alleges that compliance with these conditions is demonstrated through the use of steel production records and emission factors established in PSD permit 95010001. *Id.* Petitioner alleges that neither the title V nor the PSD permit identifies the source of the emission factors. Further, Petitioner asserts that neither the Project Summary nor the Responsiveness Summary provides evidence that the emissions factors are representative of the emissions at the USS facility. *Id.* Petitioner concludes that IEPA must provide additional information about the source of the data used to calculate the emission factors and must clearly explain how the use of the emission factors is sufficient to assure compliance with the associated emission limits. *Id.* Petitioner raises specific issues for each emission limit, and they are discussed in the sections below.

a. BOF Electrostatic Precipitator (ESP) Stack Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the NO_x limit found in Condition 7.5.6(c) of the permit. Condition 7.5.6(c) sets a NOx emission limit of 69.63 tpy for the BOF ESP stack. Petitioner alleges that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the NO_x emission factor to assure compliance with the limit. According to IEPA, the emission factor is based on the testing of NO_x emissions performed by the source. However, IEPA does not provide information on the testing data used to develop the emission factors, other than the fact that testing occurred. *Id.* Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "NO_x emission limits and emission factor had been established in the production increase construction permit 95010001 and based on the testing of NO_x emissions performed by the source. This data along with the steel production records are sufficient to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act." Responsiveness Summary at 33. However, IEPA has not made clear how the emission factors are indicative of the emissions at USS's facility, since it has failed to include in either the Responsiveness Summary or the permit record specific information on the testing of NOx emissions or references to the tests performed. IEPA has failed to explain how the use of the emission factors in conjunction with the production records is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the VOM limit found in Condition 7.5.6(c) of the permit. Condition 7.5.6(c) sets a VOM emission limit of 10.74 tpy for the BOF ESP stack. Petitioner alleges that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the VOM emission factor to assure compliance with the limit. Petition at 22-23. According to IEPA, the emission factor is based on the testing of VOM emissions performed by the source. However, IEPA does not provide information on the testing data used to develop the emission factors, other than the fact that testing occurred. A single stack test cannot reflect the variability in emissions throughout the range of operating conditions of the blast furnaces or the potential for emissions to change over time. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "VOM emission limits and emission factor had been established in the production increase construction permit 95010001 and based on the testing of VOM emissions performed by the source. This along with the steel production records are sufficient to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act. 35 IAC 219.301 regulates organic photochemical reactive materials (mostly solvents) and/or organic materials having odor nuisance. Organic solvents are not used at BOF and no odor problems directly attributed to BOF have been adjudicated or confirmed." Responsiveness Summary at 34. However, IEPA has not made clear in the permitting record how the emission factors are indicative of the emissions at USS's facility, since it has failed to include in either the Responsiveness Summary or the permit record specific information on the testing of NOx emissions or references to the tests performed. IEPA has failed to explain how the use of the emission factors in conjunction with the production records is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the carbon monoxide (CO) limit found in Condition 7.5.6(c) of the permit, stating that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the CO emission factor to assure compliance with the limit. According to IEPA, the emission factor is based on the testing of CO emissions performed by the source and has a margin of compliance of ten times the actual emissions measured during a stack test. However, IEPA does not provide information on the testing data used to develop the emission factors, other than the fact that testing occurred. Petition at 23. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "CO emission limit and emission factor had been established in the production increase construction permit 95010001 and based on the testing of CO emissions performed by the source (actual stack test results conducted in October 2006 demonstrate CO emission 10 times lower than established 95010001 permit). All these, along with the steel production records, are sufficient to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act." Responsiveness Summary at 34. However, IEPA has not made clear in the permitting record how the emission factors are indicative of the emissions at USS's facility, since it has failed to include in either the Responsiveness Summary or the permit record specific information on the testing of CO emissions or references to the tests performed. IEPA has failed to explain how the use of the emission factors in conjunction with the production records is adequate to assure compliance. In addition, although IEPA states that there is a large margin of compliance (stating actual emissions are ten times lower than the permit limit), there is no information in either the Responsiveness Summary or the permit record which addresses the variability in emissions. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the lead limit found in Condition 7.5.6(c) of the permit, stating that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the lead emission factor to assure compliance with the limit. Furthermore, Petitioner is concerned that the emissions limit is much higher than necessary given the emission factor cited by the permit. Petition at 23. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "The most significant source of lead emissions from BOF shop is a BOF ESP stack (see Condition 7.5.6(c)). The initial testing data indicates the actual level of lead emissions from ESP stack is around 3.5% of the allowable levels established in this condition." Responsiveness Summary at 35. However, IEPA does not make clear in the permitting record how the emission factors are indicative of the emissions at USS's facility or how the use of the emission factors in conjunction with the production records is adequate to assure compliance. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

b. BOF Roof Monitor Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the lead limit found in Condition 7.5.6(d) of the permit as it relies on an emission factor from an unspecified source. Although IEPA responds that there is a generous margin of compliance between actual testing emissions data and the emissions limit given in the permit, Petitioner alleges that IEPA has provided no further information to explain the source of these conservative estimates and how they are sufficient to assure compliance with the limit. Petition at 24. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that its limits are "based on conservative estimates whereas the actual emissions still maintain a generous margin of compliance." Responsiveness Summary at 35. The record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide the source of the emission factors and explain how the use of the emission factors in conjunction with production records is adequate to assure compliance. IEPA must also explain in the record how the margin of compliance is adequate, and that variability in emissions will not result in an exceedance of the emission limits. Therefore, I grant the petition on this issue.

c. Desulfurization and Reladling (Hot Metal Transfer) Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the VOM limit found in Condition 7.5.6(e) of the permit, stating that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the VOM emission factor to assure compliance with the limit. Petition at 24. Petitioner alleges that, although IEPA claims that its emission limit is based on engineering estimates, it does not explain what engineering estimates were used to develop the emission limit and how those estimates are representative of desulfurization and reladling emissions at USS's facility. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "VOM emission limits and emission factor had been established in the production increase construction permit 95010001 and based on the testing of VOM emissions performed by the source. This along with the steel production records are sufficient to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act." Responsiveness Summary at 34. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide the source of the emission factors or engineering estimates and explain how the use of the emission factors in conjunction with production records is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Condition 7.5.6(e) sets a lead emission limit of 0.09 tpy for desulfurization and reladling (hot metal transfer) emissions. Petitioner alleges that IEPA has not provided a clear rationale for the monitoring requirements associated with this limit as it relies on an emission factor from an unspecified source. The Responsiveness Summary states that the limit is "based on conservative estimates where as the actual emissions still maintain a generous margin of compliance."However, Petitioner alleges that IEPA has provided no further information to explain the source of these conservative estimates and how they are sufficient to assure compliance with the limit. Petitioner asserts that IEPA must provide additional information to justify the monitoring requirements associated with this condition. Petition at 24. Petitioner asserts that if IEPA cannot provide sufficient justification, the permit must be revised to require additional periodic monitoring, such as an annual stack test, to assure compliance with the lead limit. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "All other much smaller limits for lead emissions listed by commenter are based on conservative estimates where as the actual emissions still maintain a generous margin of compliance." Responsiveness Summary at 35.

In the case of the USS permit action, the record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide the source of the emission factors and an explanation of why the use of the emission factors is adequate to assure compliance. IEPA must also explain in the record how the margin of compliance is adequate, and that variability in emissions will not result in an exceedance of the emission limits. Therefore, I grant the petition on this issue.

d. BOF Additive System Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} limit found in Condition 7.5.6(f) of the permit, stating that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the emission factor to assure compliance with the limit. Petition at 25. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "The quantity of PM10 emissions from the BOF Additive system controlled by a hopper baghouse when compared to the BOF primary operations is minor. PM10 emission factors, along with the steel production records, are sufficient to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act. Coupled with inspection requirements, the likelihood of exceedance is minimal." Responsiveness Summary at 36. The record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has also failed to explain how the use of the emission factors in conjunction with production records is adequate to assure compliance. Therefore, I grant the petition on this issue.

e. Flux Conveyor, Transfer Pits, and Binfloor Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} limit found in Condition 7.5.6(g) of the permit, stating that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the emission factor to assure compliance with the limit. Petition at 25. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "PM10 emission factors, along with the steel production records, are sufficient to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act. Coupled with inspection requirements, the likelihood of exceedance is minimal." Responsiveness Summary at 36. The record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has also failed to explain how the use of the emission factors in conjunction with production records is adequate to assure compliance. Therefore, I grant the petition on this issue.

f. Emissions from the Argon Stirring Station and Material Handling Tripper

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} limit found in Condition 7.5.6(i) of the permit, stating that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the emission factor to assure compliance with the limit. Petition at 25. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "PM10 emission factors, along with the steel production records, are sufficient to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act. Coupled with inspection requirements, the likelihood of exceedance is minimal." Responsiveness Summary at 36. The record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has also failed to explain how the use of the emission factors in conjunction with production records is adequate to assure compliance. Therefore, I grant the petition on this issue.

F.1. Continuous Casting - Opacity

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the five percent opacity limit for the continuous caster spray chambers or continuous casting operations set in Condition 7.6.3-1(b)(ii) of the permit. Petition at 25. According to Petitioner, the USS permit requires weekly opacity observations for uncaptured roof monitor emissions, or daily observations if a previous observation measured five percent opacity or more, until five consecutive readings measure less than five percent opacity. *Id.* Petitioner asserts that IEPA has not provided a rationale that demonstrates that this monitoring is "sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." *Id.* Petitioner concludes that IEPA must revise the permit to require at least daily opacity observations to assure compliance with the opacity limit. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "Changes have been made. Condition 7.6.8-1(c)(i) of the final CAAPP identifies frequency (weekly and daily) of opacity reading from continuous casting operations." Responsiveness Summary at 38. In addition, IEPA refers to previous responses in which it contends that there is no stack in which to install a monitor or to perform a stack test. *Id.* Although IEPA addressed why it believed a continuous opacity monitor is not necessary, IEPA's response did not provide an analysis to demonstrate how the weekly (and potentially daily) opacity observations are adequate to assure compliance with the five percent opacity limit, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. IEPA refers to the frequency of the opacity readings from continuous casting operations, but does not provide any support for how it justifies the weekly (or daily) readings. Therefore, I grant the petition on this issue.

F.2. Continuous Casting - Production and Emission Limits

Petitioner's Allegations:

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with the PM_{10} and NO_x emission limits in Conditions 7.6.7(a)-(e) for the continuous casting and related operations. Petitioner alleges that compliance with this condition is demonstrated through the use of steel production records and emission factors established in PSD permit 95010001. Petition at 25. Petitioner alleges that neither the title V nor the PSD permit identifies the source of the emission factors. Further, Petitioner asserts that neither the Project Summary nor the Responsiveness Summary provides evidence that the emissions factors are representative of the emissions at USS's facility. *Id.* at 25-26. Petitioner concludes that IEPA must provide additional information about the source of the data used to calculate the emission factors and must clearly explain how the use of the emission factors is sufficient to assure compliance with the associated emission limits. *Id.* at 26.

EPA Response:

In its Responsiveness Summary regarding Condition 7.6.7(b), IEPA asserts that "No changes were made. There is no stack for caster molds with which to install a monitor and/or perform a stack test. Emission factors and recordkeeping requirements are sufficient to yield compliance with Condition 7.6.7(b)." For Conditions 7.6.7(a-e), IEPA responds, "No changes were made. Number of operations from above do not have individual stacks and emissions associated with those units are uncaptured and/or not controlled. Emission factors, recordkeeping requirements and opacity reading are sufficient to yield compliance with different emission limits of Condition 7.6.7." Responsiveness Summary at 38.

The permit record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has also failed to explain how the use of the emission factors in conjunction with production records is adequate to assure compliance. Therefore, I grant the petition on this issue.

G.1. Hot Strip Mill - Slab Reheat Furnaces

Petitioner's Allegations:

Petitioner alleges the permit does not include periodic monitoring sufficient to assure compliance with the PM_{10} limit in Condition 7.7.3-1. Petition at 26. The requirement to test once in five years at the time of renewal of the title V permit for compliance with this condition does not constitute period monitoring and is not "sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." *Id.* Petitioner concludes that, because USS must comply with the PM limit on a continuous basis, the permit must require additional periodic monitoring such as the use of a PM CEMS to assure compliance with the limit. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "Changes have been made. Condition 7.7.8(d) of the final CAAPP establishes frequency of testing PM 10 emissions (once in five years at the time of CAAPP renewal) from slab reheat furnaces. Also, PM CEM's do not measure PM10 directly." Responsiveness Summary at 39. Although IEPA addresses why it believes a CEMS is not necessary, IEPA's response did not provide an analysis to demonstrate how the testing once every five years is adequate to assure compliance with the PM_{10} limit, or is sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. IEPA refers to the frequency of the PM_{10} readings from the hot strip mill slab reheat furnace operations, but does not provide any support for this or how it justifies the testing frequency of once every five years. Therefore, I grant the petition on this issue.

Petitioner also suggests that CEMS be considered the means to comply with the periodic monitoring requirements of part 70. Although CEMS may be the preferred type of monitoring in some instances, they are not always necessary to assure compliance with applicable requirements. Section 504(b) of the Act provides that "continuous emissions monitoring need not be required if alternative methods are available that provide sufficiently reliable and timely information for determining compliance." 42 U.S.C. § 7661c(b). *See also, In the Matter of Alliant Energy WPL - Edgewater Generating Station*, Petition Number V -2009-02) (August 17, 2010), at 11.

Petitioner has neither identified an applicable requirement that compels the use of CEMS nor demonstrated that a CEMS is the only monitoring that can assure compliance with the applicable requirements. I am ordering IEPA either to explain how the USS permit provides adequate monitoring or to modify the permit to ensure that it contains monitoring sufficient to assure compliance with the applicable requirements. Therefore, I deny the claim in the petition seeking an order that IEPA must require the use of CEMS in the USS CAAPP permit.

G.2. Hot Strip Mill - Production and Emission Limits

Petitioner's Allegations:

Petitioner asserts that the permit does not include periodic monitoring sufficient to assure compliance with the PM_{10} emission limits found in Condition 7.7.7(b) of the permit. Petition at 26. Petitioner claims that, although Condition 7.7.7(b) requires compliance with a maximum hourly heat input limit, Condition 7.7.10(b) requires only that USS keep a monthly log of fuel usage. *Id.* at 26-27. Petitioner asserts that the permit must contain an hourly fuel usage recordkeeping requirement.

EPA Response:

In its Responsiveness Summary, IEPA states that "Condition 7.7.7(b) of the final CAAPP was revised in order to remove obsolete total heat input of all reheat slab furnaces (1915 million BTU per hour). Current total maximum heat input is 1/3 lower than that limit." Responsiveness Summary at 39. IEPA concedes that the previous limit was obsolete. However, its response did not provide an analysis to demonstrate how the new heat input limit is adequate to assure compliance with the PM_{10} limit, nor explain why the monthly fuel log is sufficient to assure compliance with the permit terms or yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. Therefore, I grant the petition on this issue.

H. Finishing Operations

Petitioner's Allegations:

Petitioner claims that the permit does not include periodic monitoring sufficient to assure compliance with the hydrochloride (HCl) limits contained in Condition 7.8.5(a) of the permit. The petitioner states that it is unclear why the USS permit provides for an alternative testing schedule in Condition 7.8.8(a)(iii), which requires HCl performance testing "either annually or according to an alternative schedule that is approved by the applicable permitting authority, but no less frequently than every 2 ½ years or twice per Title V permit term." Petition at 27. Petitioner asserts that, if the permitting authority approved an alternate testing schedule, as allowed by Condition 7.8.8(a)(iii), the public would not know what testing frequency was required. *Id.* Petitioner concludes that the permit must be revised to require HCl performance testing on at least an annual basis. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "Changes have been made. Condition 7.8.8(1) and (b) of the final CAAPP adopts a 2.5 year interval between the tests required by 40 CFR 63.1161 and 63.1162. This schedule is in line with an option established by 63.1162(a)(1). The IEPA retains the rights to request more frequent tests, if needed." Responsiveness Summary at 39. Although IEPA refers to the underlying applicable requirement option, it did not provide an analysis to demonstrate how the new time interval is adequate to assure compliance with the HCl limit, nor explain why the monitoring is sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. Therefore, I grant the petition on this issue.

I.1. Boilers - PM_{10} Emission Limit

Petitioner's Allegation:

Petitioner claims the permit does not include periodic monitoring sufficient to assure compliance with the PM_{10} emission limit for the boilers in Condition 7.10.3(b)(ii). Petition at 27. Petitioner states that the emission limit must be met on a continuous basis but that the permit only requires performance testing once every five years. Petitioner argues this one-time test does not constitute periodic monitoring and is not sufficient to assure compliance. Petitioner argues the permit must be revised to require additional periodic monitoring, such as the use of a PM CEMS. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states: "This regulation [40 C.F.R. § 63.1162] will never become applicable because the boilers are only allowed to burn gaseous fuels .... This was done to limit the requirements associated with case-by-case determination." IEPA's response did not provide an analysis demonstrating how performance testing once every five years is sufficient to assure compliance with a limit that applies on a continuous basis. IEPA also states that the boilers will only be allowed to burn gaseous fuels. The intent of this sentence is unclear. It appears IEPA is asserting that burning of gaseous fuels only will result in PM_{10} emissions that are below the limit, but IEPA has not provided any support for such a conclusion. It is also unclear why IEPA believes 40 C.F.R. § 63.1162 is not applicable if the boilers are limited to burning gaseous fuel. Therefore, I grant the petition on this issue.

Petitioner also concludes that CEMS be considered the means to comply with the periodic monitoring requirements of part 70. Although CEMS may be the preferred type of monitoring in some instances, they are not always necessary to assure compliance with applicable requirements. Section 504(b) of the Act, 42 U.S.C. § 7661c(b), provides that "continuous emissions monitoring need not be required if alternative methods are available that provide sufficiently reliable and timely information for determining compliance." 42 U.S.C. § 7661c(b). *See also, In the Matter of Alliant Energy WPL - Edgewater Generating Station*, Petition Number V -2009-02 at 11 (August 17, 2010). Petitioner has neither identified an applicable requirement that compels the use of CEMS nor demonstrated that a CEM is the only monitoring method that can assure compliance with the applicable requirements. I am ordering IEPA either to explain how the USS permit provides adequate monitoring or to modify the permit to ensure that it contains monitoring sufficient to assure compliance with the applicable requirements. Therefore, I deny the claim in the petition seeking an order that IEPA must require the use of CEMS in the USS CAAPP permit.

I.2 Boilers - CO Emission Limit

Petitioner's Allegation:

Petitioner claims the permit lacks periodic monitoring sufficient to assure compliance with the CO emission limit for the affected boilers in Condition 7.10.3(e). Petition at 27. Petitioner claims IEPA has not provided a clear rationale supporting the monitoring requirements associated with the limit. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA refers to a "case-by-case determination permit that requires a CO CEMS and some testing as well." Responsiveness Summary at 40. The permit to which IEPA refers is a permit which it is preparing pursuant to section112(g) of the Act, 42 U.S.C. § 7412(g). However, IEPA has yet to issue this permit; therefore, the terms of the permit are not effective. It does not appear that IEPA has included any of the terms of this draft section 112(g) permit in the CAAPP permit. I grant the petition on this issue. IEPA must explain what monitoring is required by the CAAPP permit, and how the monitoring required by the permit is sufficient to assure compliance with the permit condition or yields reliable data from the relevant time period that are representative of the source's compliance with the permit.

J. Internal Combustion Engines

Petitioner's Allegation:

Petitioner claims that the permit requires USS to demonstrate compliance with Condition 7.11.7(b) for PM, CO, NO_x, and SO_2 emission limits for the emergency generator through the use of emergency generator operation records and emission factors identified in the permit. Petition at 28. Petitioner notes the USS permit indicates the emission factors were established in permit 000600003, but that neither of the permits, nor the Responsiveness Summary, identifies the source of the emission factors. Petitioner argues that the use of emission factors from unknown sources cannot be assumed to assure compliance with emission limits. Petitioner asserts that IEPA must provide additional information to justify the monitoring requirements. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that the permit "requires a stack testing of emergency generator if the total operation exceeds 500 hr/yr .... Under normal/actual operation scenario, this emergency generator is used only several hours per day." Responsiveness Summary at 41. IEPA failed to address Petitioner's comment that the limits in permit 000600003, and compliance with those limits, were based on emission factors of unknown origin. IEPA has also not explained how the monitoring requirements in the permit are sufficient to assure compliance with the limits. Although IEPA stated in its response that stack testing is required if operation exceeds 500 hours in a year, it is not clear how this testing is sufficient to assure compliance with the limits. Condition 7.11.7(a) limits the operation of the emergency generator to 500 hours per year. Therefore, the stack testing to which IEPA refers is only applicable if the source exceeds its operational limit. I grant on this issue and order IEPA to provide an adequate explanation of whether the monitoring in the permit, including the use of emission factors, is sufficient to assure compliance with the CO emission limit.

K. Gasoline Storage and Dispensing

Petitioner's Allegation:

Petitioner claims that the permit fails to include adequate periodic monitoring to assure compliance with the hourly discharge limit on organic material into the atmosphere in Condition 7.12.3(b)(ii). Petition at 28. Petitioner argues that IEPA has failed to adequately justify how the use of the TANKS program and monthly throughput information is sufficient to assure compliance with an hourly discharge limit. *Id.* Petitioner further asserts that monthly gasoline throughput records do not appear to constitute "reliable data from the relevant time period that are representative of the source's compliance with the permit." *Id.* Petitioner concludes that IEPA must provide additional information to justify the monitoring requirements associated with this condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA stated that no changes were made because "compliance . . . is achieved by using TANKS program and monthly gasoline throughput, considering that station [is] in service for 24 hours/day. Recordkeeping requirements of Condition 7.12.9 and compliance procedures of Condition 7.12.12 are sufficient to meet monitoring requirements." IEPA's response merely restates the monitoring requirements in the permit, but does not provide an analysis to demonstrate how the TANKS program and information on monthly gasoline throughput is adequate to assure compliance with the hourly discharge limit, or why these requirements are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. Therefore, I grant the petition on this issue.

III. The Permit Lacks Compliance Schedules to Remedy All Current Violations

Petitioner's Allegations:

Petitioner raises two issues with regards to compliance schedules, alleging that a) the permit forgoes a required enforceable compliance schedule in favor of an unacceptable "under review" compliance provision, and b) there are 21 additional instances of current noncompliance given by two notices of violations (NOVs), one given in January 2009 and the other in March 2009. Petition at 28. These are discussed in more detail below.

A. Compliance Schedule

Petitioner's Allegations:

Petitioner states that IEPA and USS entered into a consent order in December 2007 that required USS to submit to IEPA a detailed compliance schedule regarding air pollution violations for basic oxygen furnace operations by March 31, 2008, and to implement the schedule by June 30, 2008. Petition at 29, citing Consent Order 05-CH-750, *Illinois ex. rel. Lisa Madigan v. U.S. Steel Corporation, Inc.*, Dec. 18, 2007, Circuit Court, Third Judicial Circuit, Madison County, Illinois. Petitioner alleges that the permit and Responsiveness Summary show that USS had not submitted an approvable schedule at the time of permit issuance. *Id.* Petitioner claims that by issuing a final permit without making an approved compliance schedule available for review, IEPA deprived the public of an opportunity to comment on a critical aspect of the permit. *Id.* at 29-30.

EPA Response:

EPA believes that, because consent decrees (CD) reflect the conclusion of a judicial or administrative process resulting from the enforcement of "applicable requirements" under the Act, all CAA-related requirements in such CDs are appropriately treated as "applicable requirements" and must be included in title V permits, regardless of whether the applicability issues have been resolved in the CD. This view is consistent with: (1) EPA's part 70 regulations, (*see*, *e.g.*, 40 C.F.R. § 70.5(c)(8) (compliance schedules "shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject")); (2) statements EPA made at the time these regulations were issued, (*see*, *e.g.*, 57 Fed. Reg. 32250, 32255 (July 21, 1992) (preamble to the 1992 final part 70 rule) ("[s]ources seeking to obtain or renew a part 70 permit cannot be shielded from enforcement actions alleging violations of any applicable requirements (including orders and consent decrees) that occurred before, or at the time of, permit issuance.")); and (3) EPA's practice implementing title V. *See, e.g., In the Matter of East Kentucky Power Cooperative, Inc. Hugh L. Spurlock Generating Station Maysville, Kentucky*, Petition IV-2006-4 (August 30, 2007), at 17 ("should the proposed consent decree be entered by the court in the related enforcement action, [the State and the source] would need to appropriately respond by incorporating the compliance schedule(s) required by the consent decree into the permit."); *In the Matter of Dynergy Northeast Energy Generation*, Petition No. II-2001- 06, at 29-30 ("conditions from [a] 1987 Consent Decree are applicable requirements that must be included in [the source's] title V permit."); *see also Sierra Club v. EPA*, 557 F.3d 401, 411 (6th Cir. 2008) (noting EPA's view that, once a CD is final, it will be incorporated into the source's title V permit). *See also* EPA's discussion in the *CITGO* at 12-13.

EPA's regulations at 40 C.F.R. § 70.6(c)(3) require that title V permits contain "[a] schedule of compliance consistent with [section] 70.5(c)(8)." In turn, section 70.5(c)(8) requires, among other things, that compliance schedules "shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject." 40 C.F .R. § 70.5(c)(8)(iii)(C). *CITGO* at 12-13.

In response to this issue, IEPA noted that USS had submitted a revised compliance schedule under the consent order in July 2009 and that this revised document was under review. The terms of the consent order, however, are applicable requirements that are not reflected in the permit. The consent order required USS to implement the terms of the compliance schedule by June 30, 2008. As IEPA explained, though, the compliance schedule was still under review at the time of permit issuance. If a source is not in compliance with an applicable requirement at the time of permit issuance, EPA's regulations require that a title V permit contain a "schedule of compliance consistent with [40 C.F.R.] § 70.5(c)(8)." See 40 C.F.R. § 70.6(c)(3). This schedule of compliance must include "an enforceable sequence of actions with milestones, leading to compliance." See 40 C.F.R. § 70.5(c)(8)(iii)(C). *CITGO* at 12-13. EPA therefore grants the petition on this issue and directs IEPA to issue a permit that assures compliance with the December 18, 2007, consent order.

B. Notices of Violation

Petitioner's Allegations:

Petitioner further references two NOVs issued to USS by IEPA in January and March 2009 after IEPA issued the draft CAAPP permit and Project Summary. *Id.* at 30. Petitioner concludes that, given these allegations of violations, "it is vital that USEPA require IEPA to develop approved, enforceable schedules of remedial measures with milestones leading to compliance…." *Id.*

EPA Response:

The issuance of an NOV, and reference to information contained therein, are generally not, by themselves, sufficient to satisfy the demonstration requirement under section 505(b)(2) of the Act, 42 U.S.C. § 7661d(b)(2). *See, generally, In the Matter of Georgia Power Company, Bowen Steam - Electric Generating Plant, et al,* (January 8, 2007 at 5-9); *In the Matter of East Kentucky Power Cooperative, Inc., Hugh L. Spurlock Generating Station,* Petition No. IV-2006-4 (August 30. 2007) at 13-18. Section 113(a)(1) of the Act, 42 U.S.C. § 7413(a)(1), provides that, "[w]henever, on the basis of any information available to the Administrator, the Administrator finds that any person has violated or is in violation of any requirement or prohibition of an applicable implementation plan or permit, the Administrator shall [issue an NOV]." An NOV is simply one early step in EPA's process of determining whether a violation has, in fact, occurred. This step is commonly followed by additional investigation or discovery, information gathering, and an exchange of views, all of which occur in the context of an enforcement proceeding, and are important means of fact-finding under our system of civil litigation. An NOV is not a final agency action and is not subject to judicial review. It is well recognized that no binding legal consequences flow from an NOV, and an NOV does not have the force or effect of law. *See PacifiCorp* v. *Thomas,* 883 F.2d 661 (9th Cir. 1988); *Absetec*

Constr. Servs. v. EPA, 849 F.2d 765, 768-69 (2nd Cir. 1988); *Union Elec. Co.* v. *EPA,* 593 F.2d 299, 304-06 (8th Cir. 1979); and *West Penn Power Co.* v. *Train,* 522 F.2d 302, 310-11 (3rd Cir. 1975). *See also, Sierra Club* v. *Johnson,* 541 F.3d at 1267; *Sierra Club* v. *EPA,* 557 F.3d at 406-409.

EPA may consider the issuance of an NOV or filing of a complaint as a relevant factor when determining whether the overall information presented by a petitioner - in light of all the factors that may be relevant - demonstrates the applicability or violation of a requirement for title V purposes. Other factors that may be relevant in this determination include the quality of the information; whether the underlying facts are disputable; the types of defenses available to the source; and the nature of any disputed legal questions, all of which EPA would consider within the constraints of the title V process. See *Sierra Club v. EPA*, 557 F.3d at 406-07. If in any particular case these factors are relevant and the petitioner does not present information concerning them, then EPA may find that the petitioner has failed to present sufficient information to demonstrate that a requirement is applicable or has been violated.

Another factor EPA considers is that the Act's enforcement and permitting authorities are complementary and it is reasonable to give full effect to both. See, e.g., *Sierra Club v. EPA*. 557 F.3d at 405-412 (discussing several aspects of the relationship between the enforcement and permitting authorities and processes). The Act provides EPA relatively short time periods in which to review title V permits. Under section 505(b)(1), EPA has only 45 days to review a proposed permit and determine if an objection is necessary. Similarly, under section 505(b)(2), EPA has only 60 days to review a petition seeking an objection and to determine if a petitioner has demonstrated the permit does not comply with the requirements of the Act. Congress deliberately established these short timeframes consistent with its intent that title V permitting be streamlined. The permit process may not allow EPA to fully investigate and analyze contested allegations. In contrast, the Act provides EPA with broad enforcement authority and several tools to resolve issues of compliance. For example, section 114 of the Act authorizes EPA to issue administrative information requests. And the enforcement process can involve significant information gathering through discovery, expert testimony, hearing, and the like.

In evaluating the nature of demonstration burden under section 505(b)(2) of the Act, EPA also considers the potential impact enforcement cases and title V decisions have on one another as illustrated by the following example. EPA could bring a civil judicial enforcement action for violations by a source of an applicable requirement or permit condition. The source and EPA could then be engaged in litigation over the merits of the allegations in EPA's complaint. Should EPA prevail in that enforcement proceeding, or should the source and EPA propose to settle their difference, then the court would enter judgment in the form of an order or consent decree requiring that the source achieve compliance, either pursuant to the terms of a compliance order, or, at a minimum, by a certain date. Separately, in the context of the issuance of a title V permit to the same source, the permitting authority may determine (on its own or as a result of an EPA objection) that the source is not in compliance with the applicable requirement or permit condition that is the subject of the enforcement proceeding, and require in the title V permit that the source achieve compliance pursuant to a schedule of compliance. Under such circumstances the source could challenge the permit, petition EPA for relief, and appeal to the appropriate circuit court. The source and EPA could then find themselves in two separate for a litigating essentially the same issue -- whether an applicable requirement or permit condition was violated and the appropriateness of a compliance schedule -- which risks potentially different and conflicting results.

Considering all these factors, EPA determines that the petition has failed to demonstrate that a compliance schedule is necessary. Petitioner here has only cited to unresolved NOVs issued to USS and has not provided any further information seeking to demonstrate noncompliance. The petition is denied on this issue.

IV. The Permit Unlawfully Exempts Emissions During Startup, Shutdown, and Malfunction

A. Exemptions from MACT Standards During Periods of Startup, Shutdown and Malfunctions Based on EPA's General Duty Standard Are Invalid

Petitioner's Allegations:

Petitioner claims that numerous provisions in the permit unlawfully exempt USS from otherwise-applicable MACT standards during periods of SSM. Petitioner cites to a December 2008 decision by the District of Columbia Court of Appeals, *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008), which vacated specific regulations at 40 C.F.R. § 63.6(f)(1) and (h)(1) that had exempted sources from complying with otherwise-applicable MACT standards. Petitioner argues that the logic of the Court's opinion applies equally to all exemptions from MACT limits during periods of SSM, and is not limited to the specific regulations challenged. Petitioner also cites to a July 22, 2009, letter from Adam Kushner, the director of EPA's Office of Civil Enforcement ("Kushner letter"). Petitioner argues that the Kushner letter supports its broader view of the *Sierra Club* decision, noting that the letter states: "EPA recognizes that the legality of such source category-specific provisions [i.e., an exemption during periods of SSM] may now be called into question." Petition at 31.

Furthermore, Petitioner claims that nine permit terms[6] illegally allow for broad exemptions from permit requirements during periods of SSM and IEPA's response to comments falls short of adequately explaining why these SSM exemptions are legally or factually justified pursuant to 40 C.F.R. § 70.7(a)(5). *Id.* at 32-33.

EPA Response:

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[6] Petitioner refers to the following permit terms:
Condition 7.2.5-4 - coke oven batteries shutdown and malfunction;
Condition 7.3.5 - by-product recovery plant shutdown and malfunction;
Condition 7.4.5-2.b.i - blast furnace process shutdown and malfunction;
Condition 7.4.5-2.c - blast furnace process startup;
Condition 7.5.5-2.b - basic oxygen furnace shutdown and malfunction;
Condition 7.6.5.a - continuous casting operations shutdown and malfunction;
Condition 7.7.5 - slab reheat furnaces startup;
Condition 7.10.3.g - boilers startup; and
Condition 7.10.3.h.i - boilers shutdown and malfunction.

As Petitioner summarizes, in the *Sierra Club* decision, the D.C. Circuit vacated the SSM exemption contained in 40 C.F.R. § 63.6(f)(1) and (h)(1), which were two provisions of EPA's general provisions regarding MACT standards. When incorporated into MACT regulations for specific source categories, these two provisions exempted sources from the requirements to comply with otherwise-applicable MACT standards during periods of SSM. Following the vacatur of 40 C.F.R. § 63.6(f)(1) and (h)(1), sources (nor permitting authorities) could not rely on these provisions as a basis for an exemption during periods of SSM.

As an initial response to this issue, IEPA noted that the mandate in the case (making the decision effective) had not yet been issued and that it was not making any changes to the permit. EPA finds the state's response to be reasonable. EPA agrees that 40 C.F.R. § 63.6(f)(1) and (h)(1) remained in effect until the D.C. Circuit issued the mandate in *Sierra Club*. See Kushner letter at 2. The mandate did not issue until October 16, 2009, and the USS permit was issued on September 3, 2009. Therefore at the time IEPA issued the USS permit, 40 C.F.R. §63.6(f)(1) and (h)(1) were in effect. It was reasonable for IEPA not to take action in response to the court's decision since the mandate had not been issued at the time of permit issuance. Therefore, Petitioner's claim is denied.

However, since the mandate has now been issued, EPA will address the substance of Petitioner's claim. The vacatur of 40 C.F.R. § 63.6(f)(1) and (h)(1) affected only those MACT standards that incorporated those provisions by reference and contained no other regulatory text excusing compliance during SSM events. The Kushner memo contains tables that provided EPA's initial analysis on whether or not specific MACT standards would be affected by the vacatur. In response to Petitioner's comment, it appears IEPA did review specific MACT standards and the tables in the Kushner letter in addressing the permit conditions identified by Petitioner. IEPA determined that only one of the conditions in question would be affected by the mandate. IEPA found that the SSM exemption in 40 C.F.R. part 63, subpart CCC (Steel Pickling) would be affected once the mandate issued. EPA has reviewed the permit conditions raised by Petitioner and concurs with IEPA that 40 C.F.R. part 63, subpart CCC is the only MACT standard to which USS is subject that has been affected following the issuance of the mandate. EPA has granted other issues in the Petition and ordered IEPA to address them. In that process, EPA recommends that IEPA reopen the USS permit and clarify that the SSM exemption is not available under 40 C.F.R. part 63, subpart CCC.

Finally, EPA disagrees with Petitioner's suggestion that the *Sierra Club* decision applies equally to all SSM exemptions in MACT standards. The D.C. Circuit had before it only the specific language of 40 C.F.R. § 63.6(f)(1) and (h)(1), and the decision is limited to those provisions. Thus, only those MACT standards that relied exclusively on 40 C.F.R. § 63.6(f)(1) and (h)(1) to exempt sources from MACT standards during periods of SSM are affected by the vacatur. While EPA acknowledged in the Kushner letter that the legality of SSM exemption provisions had been called into question, EPA continues to believe that SSM exemptions that are not based on 40 C.F.R. § 63.6(f)(1) and (h)(1) remain in effect until they are changed. EPA is in the process of evaluating SSM exemptions in MACT standards on a case-by-case basis and is addressing emissions during period of SSM in each standard.

B. Exemptions During Periods of Startup, Shutdown and Malfunctions Based on State Law Are Also Invalid

Petitioner's Allegations:

Petitioner claims that nine permit terms[7] illegally allow for broad exemptions from permit requirements during periods of SSM and IEPA's response to comments falls short of adequately explaining why these SSM exemptions are legally or factually justified pursuant to 40 C.F.R. §70.7(a)(5). Petition at 32-33.

EPA Response:

The Illinois SIP provision at 35 IAC § 201.262 provides that a permitting authority shall not authorize a permittee to operate in violation of emission limits and standards during startups unless the permittee has affirmatively demonstrated that it has made all reasonable efforts to, among others, minimize excess emissions. The USS permit contains a determination that the source already has made a demonstration that it has made all reasonable efforts to minimize startup emissions, duration of startups and frequency of startups. However, neither the permit nor the permit record (e.g., a statement of basis) provide any information about, or explanation of, how IEPA determined in advance that the permittee met its burden of affirmatively demonstrating that it had complied with the affirmative defense requirements of the permit. EPA is granting the petition and requiring IEPA to explain how it determined in advance that the permittee had met the requirements of the Illinois SIP at 35 IAC § 201.262, or otherwise make appropriate changes to the permit and explain how the permit ensures compliance with the requirement of the SIP. *See In the Matter of Midwest Generation LLC - Joliet Generating Station (Joliet),* Petition Number V-2004-3 (June 24, 2005), at 15.

The Illinois SIP provision at 35 IAC § 201.262 also provides that a permitting authority shall not authorize a permittee to operate in violation of emission limits and standards during malfunctions or breakdowns unless the permittee has submitted proof that continued operation is required to provide essential service, or to prevent risk of injury to personnel or severe damage to equipment. To authorize continued operation of units in violation of applicable standards, IEPA must have received proof that such operation is necessary to provide essential services, or to prevent injury to personnel or severe damage to equipment. The specific proof required in each instance usually will depend on the nature and the cause of the malfunction or breakdown. Thus, a determination that the permittee has met the requirements of 35 IAC § 201.262 to authorize continued operations during malfunction or breakdowns is a case-by-case determination. EPA therefore is granting the petition and requiring IEPA either to explain in the statement of basis how it determined in advance that the permittee had met the requirements of the Illinois SIP at 35 IAC § 201.262, or to specify in the permit that continued operation during malfunction or

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[7] Petitioner refers to the following permit terms:
Condition 7.2.5-4 - coke oven batteries shutdown and malfunction;
Condition 7.3.5 - by-product recovery plant shutdown and malfunction;
Condition 7.4.5-2.b.i - blast furnace process shutdown and malfunction;
Condition 7.4.5-2.c - blast furnace process startup;
Condition 7.5.5-2.b - basic oxygen furnace shutdown and malfunction;
Condition 7.6.5.a - continuous casting operations shutdown and malfunction;
Condition 7.7.5 - slab reheat furnaces startup;
Condition 7.10.3.g - boilers startup; and
Condition 7.10.3.h.i - boilers shutdown and malfunction.

breakdown will be authorized on a case-by-case basis if the source meets the SIP criteria. *See Joliet* at 16.

V. The Permit Fails to Include Compliance Assurance Monitoring Requirements

Petitioner's Allegations:

Petitioner claims that the compliance assurance monitoring (CAM) rule requirements found at 40 C.F.R. part 64 apply to USS because USS filed an initial CAAPP application after April 20, 1998. Petition at 33. Petitioner disputes IEPA's statement in the Project Summary that USS submitted its initial CAAPP application prior to April 1998. *Id.* Petitioner claims that National Steel Corporation[8] submitted a CAAPP application for the Granite City Works in March 1996, and IEPA deemed the application complete in May 1996. However, according to Petitioner, IEPA never acted on the May 1996 application. *Id.* Petitioner asserts that, pursuant to the Illinois CAAPP statute, IEPA's failure to act on the 1996 complete permit application within 18 months constituted final agency action on that application. *Id.* Petitioner further alleges that, because IEPA did not act on the 1996 application within the required 18 months of submission, the application cannot be considered the application for the draft USS CAAPP permit that IEPA made available for public comment in 2008. *Id.* at 34. Petitioner notes that, in May 2007, more than 9 years after the trigger date for CAM inclusion, USS submitted a CAAPP permit application to IEPA, which USS designated as the "initial application." *Id.* Petitioner claims that there are substantial differences between the 1996 and 2007 applications and highlights the 11 years between the two application submissions. *Id.* Petitioner asserts that, had IEPA issued a CAAPP permit with a five-year term in response to the 1996 application in a timely manner, USS would have submitted an application for a renewal permit in 2001, 3 years after the date the CAM rules were triggered. *Id.* Finally, Petitioner alleges that IEPA did not adequately respond to its comments on this issue. *Id.* According to Petitioner, IEPA stated in its Responsiveness Summary that the 1996 application "with a number of updates" was "the only one considered" in issuing the permit at issue. *Id.*, quoting Responsiveness Summary at 43, comment 70. Petitioner notes that IEPA further stated in the Responsiveness Summary that "most of the sources that would be subject to CAM are already covered by a MACT standard and therefore CAM would not be applicable…." *Id.* Petitioner asserts that this is untrue, citing to a number of conditions in the permit[9] that, it claims, are subject to CAM. *Id.* at 34-35.

EPA Response:

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[8] USS purchased National Steel Corporation, which was in bankruptcy, in May 2003.

[9] Petitioner refers to the following terms:
Condition 7.3.4.c - coke by-product recovery plant;
Condition 7.6.4.e - continuous casting;
Condition 7.7.4.e - slab reheat furnaces;
Condition 7.8.4.e - finishing operations;
Condition 7.9.4.e - wastewater treatment plant;
Condition 7.10.4.c – boilers; and
Condition 7.11.4.b – engines.

In general, the CAM rules require a title V applicant to submit as part of its application monitoring provisions that satisfy the requirements of 40 C.F.R. § 64.3, which the permitting authority places into the title V permit to assure compliance with applicable requirements. *See* 40 C.F.R. §§ 64.4 and 64.6. CAM applies to initial title V permits if, by April 20, 1998, the application was not yet filed or the permitting authority had not yet determined that the application was complete; if the permit has significant permit revisions; or if there are renewals of existing permits. 40 C.F.R. § 64.5(a).

National Steel submitted an initial title V permit application to IEPA in 1996. IEPA found the application complete and made a draft permit available for public comment, but did not issue a final permit. On May 29, 2007, several years after it had purchased National Steel, USS submitted an application that indicated on the cover page that it was an application for an initial title V permit, but that included only information necessary for IEPA to include conditions from the MACTs to which the Granite City Works had become subject since 1996. IEPA treated the 2007 application as an amendment to the 1996 application, and, therefore, did not do a completeness determination.

Petitioner has not demonstrated that the CAM requirements applied to the USS permit at the time it was issued. The length of time that elapses between the submission of a title V application and permit issuance is not relevant in regards to whether or not CAM applies. 40 C.F.R. § 64.5 requires CAM for sources that, among other things, apply for an initial title V permit after April 20, 1998. USS, as National Steel, applied for an initial title V permit in May of 1996, well before the CAM applicability deadline. USS had an obligation to update its permit application before IEPA noticed the draft title V permit for public comment on October 15, 2008. *See* 40 C.F.R. § 70.5(b). USS updated its application in 2007 with information on MACT requirements. However, the fact that a source becomes subject to a MACT standard does not, by itself, trigger CAM applicability. *See* 40 C.F. R. § 64.2(b)(i). Petitioner has not demonstrated that USS met any of the criteria that trigger CAM applicability.

Petitioner also suggests that 415 ILCS 5/39.5-5(j) prohibits IEPA from acting on a permit application if it has not done so within 18 months of the completeness determination. EPA disagrees with Petitioner's interpretation of the SIP language. 415 ILCS 5/39.5-5(j) provides that

> [IEPA] shall issue or deny the CAAPP permit within 18 months after the date of receipt of the complete CAAPP application..... Where the Agency does not take final action on the permit within the required time period the permit shall not be deemed issued; rather the failure to act shall be treated as a final permit action.

EPA reads this language to say that IEPA can be sued to take action on the languishing permit application, not that the permit is denied because 18 months has elapsed. This is consistent with section 502(b)(7) of the Act, which is intended to ensure against unreasonable delay by permitting authorities. Under section 502(b)(7) of the Act, state programs must provide that a failure to act on a permit application (whether initial or renewal) by the stated deadlines "shall be treated as a final permit action solely for purposes of obtaining judicial review . . . to require that action be taken by the permitting authority." EPA reads 415 ILCS 5/39.5-5(j) as implementing section 502(b)(7) of the Act.

Given the reasons cited above, I deny the petition on this issue. Petitioner has not demonstrated that CAM applied to USS for the purposes of this permit.[10]

VI. Numerous Permit Provisions Lack Practical Enforceability

Petitioner claims that numerous permit provisions lack practical enforceability. Petition at 35. Petitioner asserts that a title V permit must be sufficiently clear and specific to ensure that all applicable requirements contained therein are enforceable as a practical matter. According to Petitioner, to achieve practical enforceability, a title V permit must accurately describe operational requirements and limitations on emissions for a facility, including any alternative processes that the permitting state has selected. *Id.*, citing 40 C.F.R. § 70.6(a)(1)(iii) and (a)(3). Petitioner alleges that many provisions of the permit lack one or more of the conditions necessary for practical enforceability and must be revised. *Id.*

A. The Permit Fails to Appropriately Incorporate Plans by Reference

Petitioner's Allegations:

Petitioner claims that the CAAPP permit does not sufficiently identify the plans or portions of plans that are incorporated into the USS title V permit by reference. *Id.* at 36. Petitioner asserts that IEPA must incorporate clearly and on the face of the permit, rather than in the Responsiveness Summary, the following plans:

1. fugitive particulate matter operating plan;
2. PM10 contingency measure plan;
3. episode action plan;
4. soaking plan; and
5. work practice plan. *Id.* at 36-37.

EPA Response:

In its Responsiveness Summary, IEPA stated that

> IEPA approval is not required for a plan for fugitive PM operating program. The only requirement is for a review of the plan.... Incorporation by reference is the act of including a second document within another document by only mentioning the second document. If done properly, the entire second document became a part of the main

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[10] 40 C.F. R. §64.5(c) states: "... if a part 70 or 71 permit is reopened for cause by EPA or the permitting authority pursuant to § 70.7(f)(1)(iii) or (iv), ... the applicable agency may require the submittal of information under this section for those pollutant-specific emissions units that are subject to [Part 64] and that are affected by the permit reopening." This regulation authorizes IEPA to incorporate CAM if it chooses to do so during a permit reopening. See also section 64.5(a)(2).

> document. In order for a document to be properly incorporated by reference, there are 3 criteria: 1) document have existed at the time the main document was created; 2) the main document must describe the particular document to be incorporated with enough specificity to be identified; and 3) must clearly identify the intent that the document be incorporated by reference.

However, this differs from how EPA specifies incorporating documents by reference.

EPA has discussed incorporation by reference in several guidance documents and title V orders. *See e.g., White Paper 2*; *In the Matter of Tesoro Refining and Marketing,* Petition No. IX-2004-6 (March 15, 2005)(*Tesoro*), at 9; *In the Matter of Proposed Clean Air Act Title V Operating Permit Issued to Premcor Refining Group, Inc., for Operation of Port Arthur Refinery*, Petition No. VI-2007-2 (February 16, 2007), at 29. Incorporation by reference may be appropriate where the cited requirement is part of the public docket or is otherwise readily available, clear and unambiguous, and currently applicable. *Tesoro* at 9. As EPA explained in *White Paper 2,* it is important to exercise care to balance the use of incorporation by reference with the need to issue permits that are clear and meaningful to all affected parties, including those who must comply with or enforce their conditions. *White Paper* 2 at 34-38. See also *Tesoro* at 8. In order for incorporation by reference to be used in a way that fosters public participation and results in a title V permit that assures compliance with the Act, it is important that: (1) referenced documents be specifically identified; (2) descriptive information such as the title or number of the document and the date of the document be included so that there is no ambiguity as to which version of a document is being referenced; and (3) citations, cross references, and incorporations by reference are detailed enough that the manner in which any referenced material applies to a facility is clear and is not reasonably subject to misinterpretation. *See White Paper* 2 at 37.

Regarding the five plans identified in the petition, IEPA only provided general information in the USS title V permit about what it intended to incorporate by reference. In particular,

1. IEPA incorporated the fugitive particulate matter operating plan into the permit in Condition 5.3.3. The permit requires that the plan contain the minimum provisions identified in 35 IAC 212.310, amended from time-to-time, and submitted to IEPA. Neither the permit nor the SIP requires IEPA's approval of the plan. The permit, however, did not refer to a specific version of the plan nor did it provide sufficient descriptive information about the plan or its requirements.

2. IEPA incorporated the PM10 contingency measure plan into the permit in Condition 5.3.4. The permit requires USS to implement the approved plan upon notification by IEPA. The permit, however, did not refer to a specific version of the plan nor did it provide sufficient descriptive information about the approved plan or its requirements.

3. IEPA incorporated the episode action plan into the permit in Condition 5.3.9, not Condition 5.3.10 as cited in the petition. The permit requires USS maintain a

written episode action plan at the source and on file with IEPA which contains the information specified in 35 IAC 244.144. The permit, however, did not refer to a specific version of the plan nor did it provide sufficient descriptive information about the plan or its requirements.

4. IEPA incorporated the soaking plan into the permit in Condition 7.2.5-1(b)(i). The permit requires that an initial soaking plan be submitted to IEPA for review prior to resumption of operation of the battery based on design information and supplemented as needed with a revised soaking plan. The permit, however, did not refer to a specific version of the plan nor did it provide sufficient descriptive information about the plan or its requirements.

5. IEPA incorporated the work practice plan into the permit in Condition 7.2.5-2. The permit requires that USS maintain a written emission control work practice plan for the affected battery designed to achieve compliance with visible emission limitations for doors, topside port lids, offtake systems, and charging operations under 40 C.F.R. part 63, subpart L. Condition 7.2.5-2 (b) contains the minimum elements of the plan. Conditions 7.2.5-2 (c) and (d) include the requirements for implementing and revising the plan respectively. The permit, however, did not refer to a specific version of the plan nor did it provide sufficient descriptive information about the plan or its requirements.

Without specific identifying information (such as document date) and a sufficient description of the plan and its requirements, it is not possible to tell which version of the plan applies to USS and what requirements USS must meet pursuant to the plan. IEPA's incorporation is ambiguous and leaves room for misinterpretation and misunderstanding about what exactly is required of USS. As noted by *White Paper 2*, this can create difficulties for all parties, including those who enforce the permit. The ambiguous incorporation also greatly hinders meaningful public participation. Therefore, I grant the petition on this issue. If IEPA wants to use incorporation by reference for these plans, EPA recommends it do so consistent with the three principles from *White Paper 2* and the *Tesoro* Order so that there is no ambiguity as to which version of a document is being referenced.

B. Vague Provisions in the Permit Are Not Practically Enforceable

Petitioner's Allegations:

Petitioner claims that permit conditions must contain sufficient detail to ensure that the source and the public clearly understand permit obligations and compliance evaluation procedures. Petition at 37. Petitioner claims that the phrase "demonstrate that all reasonable steps" [11] from Condition 7.7.5(a) and "took all reasonable steps" from Condition 9.10.2.a.iv lacks specificity and therefore are not practically enforceable. *Id.*

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[11] Both the permit and the SIP at 35 IAC § 201.262 require the permittee to "demonstrate that all reasonable *efforts* are made to minimize startup emissions, duration of individual startups and frequency of startups." Although

EPA Response:

In its Responsiveness Summary, IEPA stated that "'Proper working order' and 'Reasonable steps' are direct citations of applicable regulations; no changes were made." Responsiveness Summary at 50. The Illinois SIP at 35 IAC § 201.262 provides that a permitting authority shall not authorize a permittee to operate in violation of emission limits or standards during startups unless the permit applicant "has affirmatively demonstrated that all reasonable efforts have been made to minimize startup emissions, duration of individual startups and frequency of startups." As discussed above, EPA is granting the petition as to permit Condition 7.7.5 and requiring IEPA to explain how it determined in advance that the permittee had met this requirement of the Illinois SIP, or otherwise make appropriate changes to the permit and explain how the permit ensures compliance with the requirement of the SIP.

Condition 7.7.5(a), which is derived from the SIP and is listed as a term or condition of the broad authorization in Condition 7.7.5, provides that "[t]his authorization does not relieve the Permittee from the continuing obligation to demonstrate that all reasonable efforts are made to minimize startup emissions, duration of individual startups and frequency of startups. . . ." Condition 7.7.5(b) provides broad minimum measures, presumably intended to provide some assurance that USS must make reasonable efforts to minimize emissions. It appears that IEPA intended these conditions to support IEPA's advance determination that USS has made the affirmative showing required by the SIP. But IEPA does not explain how these conditions support the broad advance authorization.

Further, in *In the Matter of Midwest Generation, LLC, Fisk Generating Station*, Petition No. V-2004-1 (March 25, 2005) (*Fisk*), EPA noted that for the permit to be practicably enforceable and ensure compliance with this SIP requirement, it must "include the startup procedures in the permit, or include minimum elements of the startup procedures that would 'affirmatively demonstrate that all reasonable efforts have been made to minimize startup emissions, duration of individual startups and frequency of startups.'" *Fisk* at 14. I direct IEPA, in responding to the grant with regard to the broad advance authorization addressed in IV.B. above, to evaluate whether, and ensure that, any permit conditions regarding startup are practicably enforceable.

With respect to Condition 9.10.2.a.iv, this provision is required by section 39.5(7)(k) of the Illinois Environmental Protection Act. Section 39.5(7)(k) is not an applicable requirement as defined at 40 C.F.R. 70.2. EPA notes that section 504(a) of the Act requires, among other things that, each title V permit shall include "enforceable" emissions limitations and standards and other provisions "as are necessary to assure compliance with applicable requirements" of the Act. Petitioner has not demonstrated that Condition 9.10.2.a.iv relates to an applicable requirement, and has not otherwise demonstrated that the condition is not in compliance with the Act.

Petitioner discusses the phrase "demonstrate that all reasonable steps," EPA believes Petitioner's issue is still relevant.

CONCLUSION

For the reasons set forth above and pursuant to Section 505(b)(2) of the Clean Air Act and 40 C.F.R. § 70.8(d), I hereby grant in part and deny in part the petition filed by Robert R. Kuehn on behalf of the American Bottom Conservancy objecting to the title V operating permit issued to the United States Steel Corporation-Granite City Works.

Dated: 1/31/11

Lisa P. Jackson
Administrator

SC 14466

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
999 18TH STREET - SUITE 500
DENVER, CO 80202-2466
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September 13, 2000

Ref: 8P-AR

Ms. Margie Perkins, Director
Air Pollution Control Division
Department of Public Health and Environment
4300 Cherry Creek Drive South
Denver, Colorado 80246-1530

Re: EPA Review of Proposed Title V Operating
Permit for TriGen-Colorado Energy Corporation

Dear Ms. Perkins:

By this letter, the U.S. Environmental Protection Agency (EPA) objects to the proposed Title V operating permit (permit number #96OPJE143) for TriGen-Colorado Energy Corporation (TriGen), proposed to be issued by the Air Pollution Control Division (Division) of the Colorado Department of Public Health and Environment. Our office received the proposed permit for review on July 31, 2000. The 45-day period for EPA review expires on September 13, 2000. This formal objection, based on our review of the proposed permit and supporting information, is issued under the authority of Title V of the Clean Air Act (Act), specifically section 505(b) of the Act, 42 U.S.C. § 7661d(b), and 40 CFR §70.8(c).

Pursuant to 40 CFR §70.8(c)(1), EPA will object to the issuance of any proposed Title V operating permit that EPA determines does not comply with applicable requirements of the Act or the operating permit program requirements of 40 CFR part 70. In accordance with 40 CFR §70.8(c)(1) and (4) and Colorado Air Quality Control Commission (AQCC) Regulation No. 3, section C.V.B.5, when EPA objects in writing to the issuance of a permit within 45 days of receipt of the proposed permit and all necessary supporting information, the Division may not issue the permit. If the Division fails, within 90 days after the date of an objection by EPA, to revise and submit a proposed permit in response to the objection, EPA will issue or deny the permit in accordance with the requirements of the Federal program promulgated under Title V of the Act, 40 CFR part 71.

Pursuant to 40 CFR §70.8(c)(2), any EPA objection to a proposed permit shall include a statement of EPA's reasons for objection and a description of the terms and conditions that the permit must include to respond to the objections. EPA's objection issues are detailed in the enclosure to this letter.

In addition to the objection issues, we have several additional concerns with the permit that are listed in the second part of the enclosure to this letter. While these items are not within the scope of our formal objection, we believe that these are important issues that we would like you to seriously consider.

If you have any questions, please feel free to contact Richard Long at (303) 312-6005 or Callie Videtich at (303) 312-6434, or your staff may contact Meredith Bond at (303) 312-6438 for technical matters, or Teresa Lukas of Regional Counsel at (303) 312-6898, for legal matters.

Sincerely,

/Signed by Throne Chambers for Clough/

Kerrigan G. Clough
Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

cc: Jim King, CO AQPD (w/ enc.)
Jeffry K. Richie, TriGen (w/ enc.)

ENCLOSURE
EPA Objection Issues and Comments Regarding the Proposed Title V Operating Permit for TriGen-Colorado Energy Corporation
(State of Colorado Permit Number #96OPJE143)

I. **OBJECTION ISSUES**

1. Single Source Issue

a. Permit, Section I, Conditions 3.1 and 3.2, page 4, treats TriGen and Coors as separate entities under Colorado's permitting regulations. This does not accord with EPA's interpretation of the "major source" definition (40 CFR §70.2), which, as applied to TriGen and Coors, would result in the TriGen power plant, including its boilers and associated equipment, and the Coors Brewery being treated as a single source. Coors originally built and owned the power plant, which is located in the middle of the brewery site in Golden, Colorado. In this case, Coors has divested itself of ownership, but not of control.

The fact that the two facilities are collocated creates a presumption of “control” relationship. We refer you to the letter from William Spratlin, EPA Region 7, to State and local air directors, dated September 18, 1995 (enclosed). We believe several criteria discussed in that letter apply to the Coors-TriGen relationship. First, the power plant is a support facility for the brewery, supplying all of the electrical power it currently generates, as well as steam, to the brewery. We have reviewed the purchase and supply contract binding the two facilities and conclude that the document provides persuasive evidence of common control through a contractual relationship. Further evidence of this control relationship is the fact that Coors uses the boilers at TriGen for disposal of volatile organic compound (VOC) emissions from the brewery. That the two facilities have different Standard Industrial Classification (SIC) codes is not relevant, since the power plant, as a support facility, is subsumed in the SIC classification for the primary facility, the brewery. For further discussion of our interpretation of the definition of “stationary source,” we refer you to the letter from Richard Long to Julie Wrend of the Division, dated November 12, 1998 (enclosed).

The single source made up of the two facilities is considered a major stationary source under Colorado AQCC Regulation No. 3 with regard to VOC emissions as well as for the other criteria pollutants identified in the permit: nitrogen oxides, sulfur dioxide, carbon monoxide, and particulate matter (PM10).

Solution: The permit must state that TriGen is considered to be part of a single source in conjunction with the Coors Brewery, for purposes of determining applicability of non-attainment area new source review (NSR) and prevention of significant deterioration (PSD) requirements and Title V operating permit requirements. Future modifications of the two facilities that make up the single source must be addressed together to calculate net emissions increases for comparison with NSR and PSD significance levels. The description of "major source" in Section I, Condition 3.1 and 3.2 must be changed to include VOCs, and the non-attainment area designation in Section I, Condition 3.1 and 3.2 must include ozone. (Also, see section III of this enclosure, "General Comments," paragraph 1, "Ozone Non-attainment Area Description.")

b. Permit, Section III, 1. Specific Conditions, Separate Source Determination entry in Permit Shield table. As stated above, the proposed Title V Permit treats TriGen and Coors as separate entities, which is contrary to EPA's interpretation that the TriGen boilers and associated equipment, and Coors brewery constitute a single source.

Solution: This section must state that TriGen is a single source operating in conjunction with the Coors Brewery.

2. Periodic Monitoring - Opacity Requirements

a. Section 114(a)(3) of the Clean Air Act requires "enhanced monitoring" at all major stationary sources. Section 504(c) requires each Title V operating permit to "set forth . . . monitoring, compliance certification, and reporting requirements to assure compliance with the permit terms and conditions." Section 504(a) requires permits to include "such other conditions as are necessary to assure compliance with applicable requirements" of the Act. These statutory requirements are implemented by corresponding EPA regulations. In particular, 40 CFR §70.6(a)(3)(i)(B) provides that where the applicable requirement does not require periodic testing or monitoring, the permit shall contain "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit...." In addition, § 70.6(c)(1) requires that "[a]ll part 70 permits shall contain the following elements with respect to compliance: (1) Consistent with paragraph (a)(3) of this section, compliance certification, testing, [and] monitoring ... requirements sufficient to assure compliance with the terms and conditions of the permit." In accordance with applicable judicial precedent interpreting the periodic monitoring rule at §70.6(a)(3), where the applicable requirement does not require any periodic testing or monitoring, section 70.6(c)(1)'s requirement that monitoring be sufficient to assure compliance will be satisfied by establishing in the permit "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." See 40 CFR §§ 70.6(a)(3)(i)(B). Where the applicable requirement already requires periodic testing or instrumental or non-instrumental monitoring, however, the court of appeals has ruled that the periodic monitoring rule in § 70.6(a)(3) does not apply even if that monitoring is not sufficient to assure compliance. In such cases, the separate regulatory standard at § 70.6(c)(1) applies instead. By its terms, § 70.6(c)(1) – like the statutory provisions it implements – calls for sufficiency reviews of periodic testing and monitoring in applicable requirements, and enhancement of that testing or monitoring through the permit as necessary to be sufficient to assure compliance with the terms and conditions of the permit. Here, the underlying applicable opacity requirement in AQCC Regulation No. 1 for boilers B001 and B002, as well as for boiler B003, contains no periodic monitoring requirement whatsoever. Thus, the provisions of § 70.6(a)(3)(i)(B) apply.

Section II of the proposed permit, Condition 1.5 requires the source to conduct a Method 9 visual emission observation of boilers B001 and B002 to measure the units' compliance with the 20 percent opacity limit of AQCC Regulation No. 1, "whenever any visible emissions, other than steam persist for more than four (4) consecutive hours." This condition, however, does not satisfy the requirement for periodic monitoring. There is no requirement in the permit that the source must periodically check to see if any visible emissions, other than steam, are occurring. Nor is there a requirement that, if visible emissions other than steam are observed, the source must undertake a four-hour watch to determine whether the emissions persist for that length of time, before conducting a Method 9 test. Finally, there is not adequate justification for allowing visible emissions to continue for four hours before collecting evidence of compliance or non-compliance. For these reasons, we believe the opacity monitoring provision in Condition 1.5 is insufficient to meet the periodic monitoring requirement of section 504 of the Act and 40 CFR § 70.6(a)(3).

Solution: In a telephone conversation on September 6, 2000, EPA Region 8 and the Division reached an agreement in principle for resolving the issue. The permit will include provisions requiring the source to conduct qualitative observations of visible emissions at least two times per day, once in the morning and once in the afternoon during daylight hours on boilers B001 and B002 when they are burning fuel oil. If the qualitative survey indicates visible emissions other than steam persisting for more than six (6) minutes, the source must conduct a Method 9 test within a reasonable period of time, not to exceed one-half hour. The source must keep records of the date, time and results of the qualitative observations. When boilers B001 and B002 are burning natural gas, records documenting all times when natural gas is being burned will satisfy the periodic monitoring requirement.

b. Permit, Section II, Condition 1.5 (for boilers B001 and B002) is problematic because it allows additional Method 9 observations to be delayed for up to 90 minutes after the first observation above the standard. For the exceptions to the

20% limit listed in condition 1.5, this schedule is not adequate to determine compliance with Regulation No. 1, which allows one value above 30% per 60- minute period. In addition, allowing up to a 90-minute break in observations once an exceedance is recorded is not likely to yield data that are representative of the source's compliance with the opacity limits. For these reasons, we believe condition 1.5 is insufficient to meet the periodic monitoring requirement of section 504 of the Act and 40 CFR §70.6(a)(3)(i)(B).

Solution: The permit must require that once an opacity exceedance is observed, additional Method 9 observations shall occur without break until two consecutive observations are in compliance. EPA discussed this issue with the Division staff on September 6, 2000, but did not reach specific agreement regarding this solution.

c. Permit Section II, Condition 2.5 for boiler B003 requires a biweekly Method 9 test for determining compliance with the 20 percent opacity limit on this coal-fired boiler. We believe this is insufficient to meet the periodic monitoring requirement of section 504 of the Act and 40 CFR § 70.6(a)(3)(i)(B), given the sensitivity of this emission point to small changes in baghouse control efficiency and coal heat value (see section I.3, below).

Solution: The permit must contain the same requirement for twice-daily visual checks with follow-up Method 9 observations, described in section I.2.a, above, for boiler B003 whenever it is operating. See further discussion in subsections d and e, below. The permittee may, as an alternative, use a continuous opacity monitoring system (COMS) that is appropriately installed, certified, operated, and maintained to measure opacity of emissions from boiler B003.

d. Permit, Section II, Conditions 2.6.1 and 2.6.2 for boiler B003 suffer from the same general problem we describe for condition 1.5 in section I.2.a, above. There is no requirement in the permit that the source actually check visible emissions. In addition, conditions 2.6.1 and 2.6.2 only require that a Method 9 observation occur the same calendar day that visible emissions are observed, but this is not adequate to monitor opacity that corresponds to observed visible emissions. Also, these conditions contain monitoring requirements for the special conditions defined in Regulation No. 1, but do not contain monitoring requirements for shutdown events, which ought to be monitored in a fashion similar to startups and other special conditions. For these reasons, we believe conditions 2.6.1 and 2.6.2 are insufficient to meet the periodic monitoring requirement of section 504 of the Act and 40 CFR §70.6(a)(3)(i)(B).

Solution: The permit must include provisions requiring the source to conduct qualitative observations of visible emissions at least two times per day (once in the morning, once in the afternoon) during daylight hours on boiler B003 during any shutdown, startup, fire building, cleaning of fire boxes, soot blowing, process modification, and adjustment of control equipment, except as provided in condition 2.6.2. If the qualitative survey indicates visible emissions other than steam persisting for more than six (6) minutes, the source must conduct a Method 9 test within a reasonable period of time, not to exceed one-half hour. The source must keep records of the date, time and results of the qualitative observations. The permittee may, as an alternative, use a continuous opacity monitoring system (COMS) that is appropriately installed, certified, operated, and maintained to measure opacity of emissions from boiler B003. We believe this approach is consistent with the agreement in principle for resolving this issue that we reached with Division staff in the September 6, 2000 conference call.

e. Permit, Section II, Condition 2.6.3 for boiler B003 is problematic because it allows additional observations to be delayed for up to 90 minutes after the first observation above the standard. For the special conditions listed in condition 2.6, this schedule is not adequate to determine compliance with Regulation No. 1, which allows one value above 30% per 60-minute period. In addition, allowing up to a 90-minute break in observations once an exceedance is recorded is not likely to yield data that are representative of the source's compliance with the opacity limits. For these reasons, we believe condition 2.6.3 is insufficient to meet the periodic monitoring requirement of section 504 of the Act and 40 CFR §70.6(a)(3)(i)(B).

Solution: The permit must require that once an opacity exceedance is observed, additional Method 9 observations shall occur without break until two consecutive observations are in compliance. EPA discussed this issue with the Division staff on September 6, 2000, but did not reach specific agreement regarding this solution.

3. Inadequate Compliance Demonstration and Periodic Monitoring - Particulate Emissions

Permit Section II, Condition 2.2 for emission unit B003 (coal fired boiler) requires the boiler to meet the particulate matter emission limit resulting from the equation in Regulation No. 1, section III.A.1.b. The unit is equipped with a baghouse for emission control. Section II, Condition 2.2, ends with a statement that: "A one time demonstration of the compliance shall be kept on record and made available for Division review upon request." However, for reasons explained below, we believe that a one-time demonstration of compliance is not appropriate for this circumstance. In addition, a one-time test does not satisfy the periodic monitoring requirements of section 504 of the Act and 40 CFR § 70.6(a)(3)(1)(B).

The Technical Review Document (TRD) prepared for this permit action states that: "TriGen needs to be mindful that small combinations of changes in the baghouse control efficiency and the coal heat value may result in an exceedance of the standard. A reduction of the control efficiency to approximately 96% may result in an exceedance of the standard for a reasonable range of coal heat contents." The performance test requirement for the Regulation No. 1 particulate emission limitation says: "Prior to granting a final approval permit or amending a permit, when an emission source or control equipment is altered, or at any time when there is reason to believe that emission standards are being violated, the Division may require the owner or operator. . . to conduct [EPA Reference method] performance tests. . . to determine compliance. . .." (See AQCC Regulation No. 1, section III.A.3.) Given these statements, we question whether a one-time demonstration of compliance comports with the underlying Colorado regulation, and we cannot consider such a one-time demonstration adequate to assure ongoing compliance for this unit (see section 504 of the Act, and 40 CFR §70.6(c)(1)).

Solution: The Division has acknowledged that a one-time calculation to demonstrate compliance is not satisfactory for this unit, but has not yet proposed appropriate language to correct the deficiency. The permit must specify appropriate stack test methods and schedule to meet the requirements of Regulation No. 1, section III.A.3. The permit must also contain appropriate periodic monitoring requirements for this source. Annual stack testing for particulate emissions, together with requirements for appropriate baghouse operation and maintenance (including record keeping) and for periodic monthly fuel sampling analysis will resolve this issue.

4. Use of Terms "Normal Operation" and "Normal Conditions" and Description of Special Conditions

   a. Permit, Section II, Subsection 2, Table on page 10, for the parameter "Opacity." The table on page 10 of the proposed permit (hereafter referred to as Table 2) contains the heading "Normal Operation" under the heading "Limitations." The term "Normal Operation" does not appear in the underlying regulation, AQCC Regulation No. 1, and could be read to exclude conditions like shutdown that are subject to Regulation No. 1's 20% opacity limitation. This would render the permit inconsistent with the applicable requirement. Thus, in our opinion, the proposed permit is inconsistent with the requirements of section 504(a) of the Act and 40 CFR §70.6(a)(1). This problem in Table 2 is compounded by language in subsection 2.6, which we discuss below. We note that the tables on pages 7 and 16 of the proposed permit do not use the heading "Normal Operation."

      Solution: Delete the heading "Normal Operation." Substitute the heading "General." (In a September 6, 2000 conference call, EPA and the Division staff discussed possible solutions to the problems identified in this Section 4. The solutions described herein and below are generally consistent with approaches on which EPA and the Division staff reached tentative agreement, although the details of the language may differ in some respects from what was discussed.)

b. Section II, Subsection 2.6: This subsection indicates that the "special conditions" referenced in Table 2 "include startup, fire building, cleaning of fire boxes, soot blowing, process modification, adjustment of control equipment and startup." It then states that "[s]hutdown, upsets and offline emissions are not included in the special activities subject to any opacity standard." This provision compounds the problem with Table 2's heading "Normal Operation," and is clearly inconsistent with the underlying applicable requirement. The language makes it appear that shutdown, upsets, and offline emissions are "special conditions," but that they aren't subject to any opacity limit. However, Regulation No. 1's only exception from the 20% opacity limit is for startup, fire building, cleaning of fire boxes, soot blowing, process modification, and adjustment of control equipment. Thus, in our opinion, the proposed permit is inconsistent with the requirements of section 504(a) of the Act and 40 CFR §70.6(a)(1). Accordingly, the language in subsection 2.6 must be changed.

Solution: Change the language of subsection 2.6 to read as follows: "The special conditions consist of startup, fire building, cleaning of fire boxes, soot blowing, process modification, and adjustment of control equipment. Shutdown, upsets, and offline emissions are not special conditions and are subject to the 20% opacity limit."

c. Section II, Subsection 20.1: The heading for this subsection is "Opacity Requirements During Normal Conditions." The term "Normal Conditions" does not appear in the underlying regulation and could be read to exclude conditions like shutdown that are subject to Regulation No. 1's 20% opacity limitation. This would render the permit inconsistent with the applicable requirement. Thus, in our opinion, the proposed permit is inconsistent with the requirements of section 504(a) of the Act and 40 CFR §70.6(a)(1).

Solution: Replace the heading with "Opacity Requirements - General."

d. Section II, Subsection 20.2: The end of the first paragraph in this subsection contains the following sentence: "This provision does not apply to periods of shutdown or malfunction." It is not clear what "This provision" refers to. Also, this language is inconsistent with the language used in subsection 2.6 and could lead to enforcement problems. Thus, in our opinion, the proposed permit is inconsistent with the requirements of section 504(a) of the Act and 40 CFR §70.6(a)(1).

Solution: Change the sentence to read as follows to make it consistent with our suggested changes for subsection 2.6: "Shutdown, upsets, and offline emissions are not special conditions and are subject to the 20% opacity limit."

5. Permit Shield

Permit, Section III, Condition 1, contains a listing of, "parameters and requirements [that] have been specifically identified as non-applicable to the facility. . .." This condition identifies the following requirements as not applicable to the facility: a) 40 CFR § 52.21, Prevention of Significant Deterioration (PSD) as not applicable to the entire plant; b) Regulation No. 3, Part B concerning construction permits, including PSD and nonattainment NSR regulations, as not applicable to boilers 1, 2, and 3; c) 40 CFR Part 60, subparts A, D, Da, and Db as not applicable to boilers 1, 2, and 3; d) 40 CFR Part 60, subparts Da and Db as not applicable to boiler 4; and e) 40 CFR Part 60, subpart Db as not applicable to boiler 5. The Division's justification for granting the permit shield is that no construction or major modifications have occurred that would have triggered PSD (or NSR) applicability, and no modifications have occurred at any boiler since the specified new source performance standard (NSPS) applicability dates.

This blanket statement cannot be made unless the Division has been provided all of the potentially relevant facts regarding new source review and NSPS applicability in TriGen's operating permit application. While the Division may have reviewed its files for TriGen to make these determinations, the source may not have notified the Division of all changes that could have triggered PSD or NSR, or that could be considered a modification subject to the NSPS. Thus, even an exhaustive review of the Division's files is not sufficient to determine whether a facility may have undergone a modification that should have triggered major modification permitting requirements or the NSPS.

Furthermore, considering EPA's interpretation that TriGen and the Coors Brewery are a single source for the purposes of permitting requirements, the Division would have to have been provided all of the relevant facts regarding any changes at the Coors Brewery as well as TriGen to determine whether PSD would have applied to any net emissions increases at the combined source. Last, this shield for TriGen is not consistent with the permit shield provisions in 40 CFR §70.6(f)(3)(ii) or with condition 2.2 of this section, which state that the permit shield shall not alter or affect the liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance.

Solution: To address this objection, the Division must delete the permit shield provisions for the entire plant and for boilers 1, 2, and 3 regarding applicability of construction permitting requirements (including PSD) in 40 CFR §52.21, 40 CFR §51.166, and Colorado Regulation No. 3 Part B. The Division must also delete the permit shield provisions for boilers 1, 2, 3, 4, and 5 regarding NSPS applicability, specifically, applicability to any modifications that may have occurred since the applicability dates. (The Division may retain the permit shield for original NSPS applicability based on the date of construction of the boilers.)

II. ADDITIONAL CONCERNS

1. Permittee's Discretion

In several places, the permit requires that the source operate units "in accordance with the manufacturer's recommendations or documented operating practices and procedures developed by the permittee." (See Section II, conditions 2.2, 12.3, and 18.1.1.) This language allows the permittee to define compliance determining parameters for various operation and maintenance requirements, with no apparent recourse if the State, EPA, or citizens, disagree with the permittee's decision. We believe that this provision potentially makes the compliance determining parameters unenforceable and conflicts with the requirement for enforceable emission limitations in section 504(a) of the Act and 40 CFR § 70.6(a)(6)(i).

Solution: In discussions, the Division and EPA agreed that replacing the objectionable phrase, ". . . or documented operating practices and procedures developed by the permittee," with ". . .or in accordance with good engineering practice," would correct this problem.

2. Periodic Monitoring -- Opacity Requirments (Diesel IC Engine)

Permit, Section II, Conditions 12.3.1 and 12.3.3 contain provisions for opacity observations for a General Motors 250 HP Diesel Fired IC Engine, #E018. These provisions suffer from some of the same flaws identified above for boilers B001, B002, and B003. Condition 12.3.1 does not require that the source actually check visible emissions during start-up, and does not specify that the Method 9 observation must occur during the start-up process. Condition 12.3.3 allows a delay of up to 60 minutes for additional Method 9 observations once an exceedance is observed. For the reasons stated above, we believe conditions 12.6.1 and 12.6.3 are insufficient to meet the periodic monitoring requirement of section 504 of the Act and 40 CFR §70.6(a)(3)(i)(B).

Solution: The permit must include provisions requiring the source to conduct qualitative observations of visible emissions after 1500 hours of engine use. If visible emissions are observed and the start-up requires longer than ten minutes, the source must immediately conduct a Method 9 test. The source must keep records of the date, time and results of the qualitative observations. The permit must require that once an opacity exceedance is observed under either condition 12.3.1 or 12.3.2, additional Method 9 observations shall occur without break until two consecutive observations are in compliance.

3. Ozone Non-attainment Area Description

Permit, Section 1, Condition 1.2 of Section I states: "The ozone non-attainment designation was recently removed by EPA and the area is considered attainment." However, EPA reinstated the 1-hr Ozone NAAQS on July 20, 2000, (see 65 FR 45182). As a result of that action, the 1-hour ozone nonattainment designation for the Denver metropolitan area will be reinstated effective January 16, 2001. Thus, the permit text is inaccurate and misleading.

Solution: In a conversation regarding this concern, the Division suggested language to correct the problem. EPA agrees that the suggested language is adequate, and offers the following clarifications (in bold):

> "The area in which the plant operates is designated as nonattainment for carbon monoxide (CO) and particulate matter less than 10 microns (PM_{10}). Although the Denver metropolitan area was previously designated for nonattainment for **the 1-hour** ozone **standard**, this **standard was revoked in June of 1998.** However, all SIP-approved requirements continue to apply in order to prevent backsliding under the provisions of Section **110(l)** of the Federal Clean Air Act.
>
> "A July 20, 2000 Federal Register **(see 65 Fed. Reg. 45182)** indicated that the **1-hour ozone** nonattainment **designation will** be reinstated **on January 16, 2001**. In addition, **based upon preliminary data, it appears that** Denver recently violated the new 8-hour ozone standard and it is the Division's understanding that EPA will issue a nonattainment **designation** Federal Register notice for the Metro area even though **the EPA's ability to implement** the standard is under judicial review as of the issuance date of this permit."

4. Stylistic Concerns with Permit Structure

Our July 24, 2000, comment letter regarding the draft permit for this source, addressed several instances where this permit's structure makes it confusing and potentially misleading. Unclear cross referencing, splitting explanations of a given applicable requirement between a summary table and text, and providing numerical expressions without defining the equation or values being used, are some examples. We should note that such stylistic concerns are not "normal" for Colorado's Title V permits.

Solution: We ask the Division to consider the comments made in our earlier letter as it prepares this and future Title V permits.

5. Missing Applicable Requirement Citations

Permit, Section II, Conditions 2.5, 2.6, 2.7, and 2.8, identify the underlying applicable requirements for the permit terms, however, neither the table nor the text addresses the opacity requirements. According to 40 CFR §70.6(a)(1)(I), "the permit shall specify and reference the origin of and authority for each term or condition, and identify any difference in form as compared to the applicable requirement upon which the term or condition is based."

Solution: The permit must be revised to include these references. The Division has indicated that it will insert references to Regulation No. 1 in the appropriate conditions. EPA notes that the Division must be careful to reference the SIP-approved version of Regulation No. 1.

6. Alternative Monitoring for NSPS

a. Permit, Section II, Condition 19.2.2 allows the source to solicit prior written approval from the Colorado Air Pollution Control Division for "alternative monitoring systems, alternative reference methods, or any other alternatives for the required continuous emission monitoring systems." As this section concerns continuous emission monitoring required under any federal requirement, including the EPA-approved SIP and the NSPS requirements, such approval can only be granted by the EPA Administrator. The July 10, 1998, memorandum from John Seitz entitled "Delegation of 40 CFR Part 63 General Provisions Authority to State and Local Air Pollution Control Agencies," which includes Parts 60 and 61, discusses case-by-case criteria under which evaluation and approval of alternative monitoring provisions under various federal regulations can be delegated to state and local agencies.

   Solution: Permit Section II Condition 19.2.2, must be revised to comport with the requirements of the New Source Performance Standards for granting approval to alternative procedures. See, 40 CFR § 60.13. Condition 19.2.2 could be revised to state: "Alternative monitoring systems, alternative reference methods, or any other alternatives for the required continuous emission monitoring systems shall not be used unless the permittee obtains prior written approval from **the appropriate agency, either the U.S. EPA** or the Division ...."

b. Permit, Appendix G details the emission calculation procedure for SO_2 and NO_X emissions, which applies to boilers B004 and B005, both of which are subject to NSPS Subpart D. The appendix states: "In a March 31, 1998 letter from the Division to TriGen, the Division stated it concurred that oxygen sensors would not be required to compute lb/MMBTU because the stack gas flow rate was not being continuously monitored." However, the authority to approve an alternative procedure such as this one cannot be delegated from the EPA to the State. NSPS Subpart D, at 40 CFR § 60.45(e)(1), states: "Alternative procedures approved *by the Administrator* shall be used when measurements are on a wet basis." The general provisions of NSPS, at 40 CFR § 60.2, define "Administrator" as the Administrator of the EPA *or his authorized representative*.

State adoption and implementation of an NSPS Subpart does not automatically make the State the *authorized representative* for approving alternative procedures under that Subpart. Instead, it is up to EPA to decide, on a *case-by-case* basis, whether authority to approve an alternative procedure under NSPS can be delegated to a State. This is explained in EPA's national guidance dated August 24, 1993 ("Procedures for Handling Requests for Minor and Major Alternatives to Compliance and Testing Methods"). While the 1993 guidance was later revised on July 10, 1998, the contents pertaining to alternative requests remained the same.

In short, the 1993 guidance states that if an alternative to an NSPS testing method or procedure is not a "minor" change in method or procedure, as described in the guidance and determined by EPA, then authority to approve the alternative cannot be delegated to the State. It appears the alternative approved by the State for TriGen is not a "minor" change.

Solution: TriGen must seek approval for the alternative monitoring procedure from EPA directly. Appendix G must be deleted and the procedures required in the 40 CFR § 60 Subpart A and D must be followed until or unless an alternative is granted.

On July 27, 2000, the Division submitted a letter to EPA acknowledging that EPA should have been the lead agency for processing the alternative monitoring request.

7. Compliance Demonstration for Emission Limitations for Coal and Ash Handling Units and Fly-ash Collection Units

Permit, Section II, subsections 5 through 11, cover the coal and ash handling units and fly-ash collection units. Each of these units is required to meet particulate matter and opacity emission limits, and throughput restrictions, established through various construction permits. Particulate matter emissions from these units are computed utilizing AP-42 emission factors and accounting for the fabric filter controls at each emission point. We have two concerns with the permit provisions for each of these units: (1) while the permit specifies that AP-42 emission factors are to be used, it does not delineate monitoring or recordkeeping for the various parameters that are necessary inputs to the AP-42 calculations, and (2) the TRD indicates that a control efficiency of 99.9% is assumed for the fabric filters, but the permit lacks both periodic monitoring of parameters that would indicate that the control device is functioning properly, and operation and maintenance requirements to support the assumed fabric filter control efficiencies.

Solution: (1) The permit must require that the source monitor and keep records of the data that is necessary for calculating its particulate matter emissions from these coal and ash handling units. The parameters needed for each unit should be specified. (2) The permit must include appropriate operation, maintenance, monitoring, and recordkeeping to show that the fabric filters are functioning properly. Parameters to monitor could include filter differential pressures, logs of maintenance activities, etc.

IN THE MATTER OF THE DRAFT TITLE V)
PERMIT FOR)
)
RRI ENERGY MID ATLANTIC POWER HOLDINGS LLC) ID NO. 17-00001
SHAWVILLE GENERATING STATION)
DRAFT TITLE V/STATE OPERATING PERMIT)
IN CLEARFIELD COUNTY, PA)
)
ISSUED BY THE PENNSYLVANIA)
DEPARTMENT OF ENVIRONMENTAL PROTECTION)

DECLARATION OF
RANAJIT (RON) SAHU

(1) I, Ranajit Sahu, am an environmental engineer with more than 18 years of experience in program and project management services; design and specification of pollution control equipment; soils and groundwater remediation; combustion engineering evaluations; energy studies; and multimedia environmental regulatory compliance and permitting, among other things. In addition to my consulting work for private industry on New Source Review and other matters, I have testified on behalf of the United States in several New Source Review enforcement actions in federal court.

(2) I have a B.S., M.S., and Ph.D. in Mechanical Engineering, the first from the Indian Institute of Technology (Kharagpur, India) and the latter two from the California Institute

of Technology (Caltech) in Pasadena, California. My research specialization was in the combustion of coal and, among other things, understanding air pollution aspects of coal combustion in power plants.

(3) A copy of my current resume is provided in Attachment A.

(4) It is my understanding that the current matter pertains to the emissions of a class of air pollutants known as particulate matter from the coal-fired boilers at the Shawville Generating Station (SGS), owned by RRI Energy Mid-Atlantic Power Holdings LLC. SGS consists of four boilers, numbered Units 1 through 4. Units 1 and 2 (1954) are dry bottom, front wall-fired balanced draft sub-critical boilers fired using bituminous coal and No. 2 oil. Units 3 (1959) and 4 (1960) are tangential fired boilers firing the same fuels.

(5) Among other pollutants, coal-fired power plant boilers such as the Shawville Units 1 through 4, can emit particulate matter (PM) or dust of varying size and chemical composition. Total suspended particulate (TSP) matter will be referred to simply as PM. Particles with an aerodynamic diameter[1] of 10 micrometers (or microns) or smaller will be denoted as PM10. Particles with aerodynamic diameters 2.5 micrometers or smaller

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[1] In air pollution control, it is necessary to use a particle size definition that directly relates to how the particle behaves in a fluid such as air. The term "aerodynamic diameter" has been developed by aerosol physicists in order to provide a simple means of categorizing the sizes of particles having different shapes and densities with a single dimension. The **aerodynamic diameter** is the diameter of a spherical particle having a density of 1 gm/cm^3 that has the same inertial properties [i.e. terminal settling velocity] in the gas as the particle of interest. See http://www.epa.gov/apti/bces/module3/diameter/diameter.htm.

will be denoted as PM2.5. By comparison, the diameter of typical human hair is around 70 to 100 micrometers.

(6) Particles collected, in any of the size classes above, are also classified into two fractions – namely the filterable and the condensable portions. Filterable particles are those that are present in a form suitably collected by a filter present in the exhaust gas path. Condensable particles are those that may be present in the vapor phase at the exhaust gas temperature but which can condense into particles at the lower temperatures present in the ambient air. Together the filterable and condensable fractions are sometimes referred to as the "total" in any size class. Finally, these total (filterable plus condensable) fractions are sometimes referred to as the primary particulates since they are directly emitted by the source boiler. Other particles that can form in the atmosphere resulting from gaseous emissions from the boiler are sometimes referred to as secondary particles.

(7) Primary particles are emitted because the combustion of coal in a boiler results in the formation of flyash, which, in turn, is due to the presence of mineral matter in coal that cannot be burned (unlike the carbon which does burn in the boiler). Some of the mineral matter transforms to bottom ash, which is not entrained in the combustion exhaust air and drops down to the bottom in the boiler. But, typically, a significant fraction (greater than 50%) of the ash is emitted from the boiler as fly ash.

(8) I have been asked to provide an opinion, in general, on how emissions of primary, filterable PM, PM10, and PM2.5 can vary from a coal-fired power plant boiler, such as any of the Shawville units, equipped with electrostatic precipitators (ESP).

(9) SGS Units 1 and 2 are each equipped with 2 ESPs, while SGS Units 3 and 4 are each equipped with 4 ESPs. All of the ESP units are "cold" side units meaning that they are located after the respective combustion air preheaters.

(10) Without any air pollution controls, the bulk of the fly ash containing filterable PM/PM10/PM2.5 would simply be emitted to the atmosphere from the boiler. However, almost all boilers use particulate control devices to prevent or minimize that. The vast majority of these are either fabric filters (typically the newer boilers) or ESPs.

(11) The basic principle of operation of ESPs is as follows. A high voltage corona discharge is used to electrically charge the flyash particles. The charged particles then migrate in an applied electric field to the collection electrode where they accumulate. For example, negatively charged particles migrate to the positive electrode. The collected particles are subsequently removed by mechanical action (or rapping) where they fall into collection hoppers for disposal.

(12) There are two major charging processes, field charging and diffusion charging. Field charging refers to the bombardment of the particles by negative ions, moving under the influence of the electric field. The charge acquired depends on the charging field, the surface area and dielectric properties of the particle, and the time available for charging. This is the most important means of charging particles greater than 1 micrometer in aerodynamic diameter. Diffusion charging results from the thermal or random motion of ions causing them to diffuse through the surrounding gas. As particles collide with the diffusing ions, charge is transferred. The charge attained in this case depends on particle size, gas characteristics, gas temperature, and the time available for charging. Diffusion

charging is most significant for particles smaller than 0.1 micrometers in aerodynamic diameter. Since both processes occur simultaneously, there is a relative minimum in combined efficiency for both processes for particle diameters around 1 micrometer in aerodynamic diameter.

(13) The overall efficacy of an ESPs is expressed in terms of its "efficiency" which is defined as the ratio of the mass of particles removed by the ESP to the mass of particles entering the ESP.

(14) The emissions of PM/PM10/PM2,5 can vary from coal-fired boilers because they depend on numerous factors. While a complete and exhaustive listing of every single factor that can affect emissions of these pollutants would be almost impossible to compile, based on my experience the following factors should be considered. I have grouped them into properties of the fuel (coal), properties of the flyash particles themselves, and factors affecting ESP performance.

(15) Collectively, all of these factors, their interactions, and their variation with time, will affect how much primary, filterable PM/PM10/PM2,5 is actually emitted. In addition, there are numerous additional factors that affect the accuracy and variability of how much PM/PM10/PM2.5 are measured. Thus, the observed variability of these emissions is a combination of the factors listed below and the factors associated with the measurement process.

(16) The more important properties of the coal that can effect PM/PM10/PM2.5 emissions are:

- Mineral matter or ash quantity. Lower the mineral matter content, less particulate emissions are produced. In addition, reduction in ash loading tends to improve ESP efficiency.

- Fly-ash electrical resistivity. Since the collection of the particles at the later ESP depends on the ability of the particles to be electrically charged, their electrical resistivity plays an important role. If the resistivity is too low, particles can lose their charge either before collection or they may be released back into the exhaust gas stream after collection. If the resistivity is too high, the collected particles cannot easily be dislodged from the ESP collecting electrode and this reduces ESP efficiency.

- Coal moisture content. Coal moisture content can affect the exhaust gas flow rate and temperature, both of which will affect collection efficiency.

- Ash chemical composition. The particle electrical resistivity as well as the ability of various exhaust gas components to condense (on other ash particles), depends on the chemical composition of the coal and the mineral matter.

- Ash particle size. Migration velocity and therefore particle collection rates decrease in proportion to the size of the particle (Darby 1983; Wibberley and Wall 1985).

(17) Properties of the particles themselves that can effect PM/PM10/PM2.5 emissions are as follows:

- Electrical characteristics. Particle electrical characteristics are determined by the resistivity of the fly-ash after it has formed an ash layer on the collecting surface. If the resistance level is high, the corona current passing through the ash layer must be generally reduced or back corona effects will reduce the performance of the ESP. The range of resistivity is affected by the chemistry of the ash, moisture in the flue gas, levels of other chemicals such as sulfur trioxide and flue gas temperature.

- Size distribution. Dust collection is affected by the particle size due to the two mechanisms of particle charging described earlier.

- Migration velocity. The speed of the movement of charged particles to the collection electrodes is denoted by the electrostatic migration velocity which, in turn, depends on a number of assumptions concerning the flow and nature of the charging mechanism. The effective migration velocity is an indication of a precipitator's ability to collect a specific sample of PM/PM10/PM2.5 at a specific operating condition. The effective migration velocity varies with particle size.

- Particle shape. Particle shape can influence collection efficiency because shape affects the ability of the particle to be charged as well as the migration properties of the particles. Angular particles tend to interlock in the collected layer on the ESP plates and be rapped/removed in a more coherent agglomerate, resulting in less re-entrainment than spherical particles.

- Particle cohesivity. Particle cohesivity (the ability to adhere to one another) on the plates of an ESP is also an important factor in relation to re-entrainment. The more cohesive the particles, the less likely they will be re-entrained into the gas stream.

- Unburnt carbon content. The unburnt carbon content for a particle is a reflection of the coal reactivity as well as the combustion conditions. High levels of unburnt carbon (which depend on combustion conditions) can affect particle resistivity.

(18) In addition to the above, important factors that affect the overall collection efficiency of an ESP include:

- Particle residence time. The time available to charge and collect a dust particle. In turn, this depends on particle shape and size. It also depends on specific geometrical aspects such as the position of the particle in relation to the electrical field at the entry to the ESP.

- Gas flow and particle concentration uniformity. If the exhaust gas flow entering the ESP is not uniform, it will adversely affect the residence time and therefore the efficiency.

- ESP Power. The overall electrical energy available to charge the ash.

- Electrode cleaning. The effectiveness of dust removal from electrodes within the ESP.

- Sneakage. This refers to ash bypassing the electrical sections of the ESP, i.e. between discharge and collection electrodes, and thus escaping capture.

- Back corona. This occurs when the ash layer on the collector surface has reached a level of resistivity that the accumulated layer breaks down and produces a flow of positive ions back towards the negative high voltage discharge electrode.

- Re-entrainment of particles. This refers to the reintroduction of particles to the gas stream from the discharge electrodes and collecting surfaces during rapping. It can also result from gas sweepage, when gas that bypasses the treatment zone of the ESP, disturbs collection zones such as hoppers.

(19) Of course, in addition to the factors listed above, the overall age, condition, deterioration, maintenance and other factors of the boilers and the ESPs will also affect the emissions of these pollutants.

(20) Given these numerous factors discussed above that can, singly and in combination, affect the emissions of these pollutants from each of the Shawville boilers, the emissions of PM/PM10/PM2.5 will likely be variable, and significantly so. For example, in my experience, it is not uncommon for such variability to be multiple-times or even an order or magnitude different between the typical three back-to-back hourly test runs in a stack test. Thus, it is highly unlikely that an occasional measurement (such as a stack test) will accurately be able to capture such variability. A stack test is a snap-shot in time and cannot possible provide any information for the periods between tests. Thus, continuous measurements of filterable PM, using CEMS that

are now available, are the proper means of accurately measuring such emissions. Such continuous measurements, done properly, will capture the variability of these emissions over time and therefore provide a more accurate record of the emissions from the Shawville units.

I declare under penalty of perjury that the foregoing is true and correct.

Ranajit Sahu

Ranajit Sahu

Executed on February 14, 2011 in Alhambra, CA

RANAJIT (RON) SAHU, Ph.D, QEP, CEM (Nevada)

CONSULTANT, ENVIRONMENTAL AND ENERGY ISSUES

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EXPERIENCE SUMMARY

Dr. Sahu has over twenty one years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment; soils and groundwater remediation; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

He has over nineteen years of project management experience and has successfully managed and executed numerous projects in this time period. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public. Notably, he has successfully managed a complex soils and groundwater remediation project with a value of over $140 million involving soils characterization, development and implementation of the remediation strategy, regulatory and public interactions and other challenges.

He has provided consulting services to numerous private sector, public sector and public interest group clients. His major clients over the past seventeen years include various steel mills, petroleum refineries, cement companies, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, and various entities in the public sector including EPA, the US Dept. of Justice, California DTSC, various municipalities, etc.). Dr. Sahu has performed projects in over 44 states, numerous local jurisdictions and internationally.

Dr. Sahu's experience includes various projects in relation to industrial waste water as well as storm water pollution compliance include obtaining appropriate permits (such as point source NPDES permits) as well development of plans, assessment of remediation technologies, development of monitoring reports, and regulatory interactions.

In addition to consulting, Dr. Sahu has taught and continues to teach numerous courses in several Southern California universities including UCLA (air pollution), UC Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management) for the past seventeen years. In this time period he has also taught at Caltech, his alma mater and at USC (air pollution) and Cal State Fullerton (transportation and air quality).

Dr. Sahu has and continues to provide expert witness services in a number of environmental areas discussed above in both state and Federal courts as well as before administrative bodies (please see Annex A).

EXPERIENCE RECORD

2000-present	**Independent Consultant.** Providing a variety of private sector (industrial companies, land development companies, law firms, etc.) public sector (such as the US Department of Justice) and public interest group clients with project management, air quality consulting, waste remediation and management consulting, as well as regulatory and engineering support consulting services.
1995-2000	Parsons ES, **Associate, Senior Project Manager and Department Manager for** Air Quality/Geosciences/Hazardous Waste Groups, Pasadena. Responsible for the management of a group of approximately 24 air quality and environmental professionals, 15 geoscience, and 10 hazardous waste professionals providing full-service consulting, project management, regulatory compliance and A/E design assistance in all areas.
	Parsons ES, **Manager for Air Source Testing Services**. Responsible for the management of 8 individuals in the area of air source testing and air regulatory permitting projects located in Bakersfield, California.
1992-1995	Engineering-Science, Inc. **Principal Engineer and Senior Project Manager** in the air quality department. Responsibilities included multimedia regulatory compliance and permitting (including hazardous and nuclear materials), air pollution engineering (emissions from stationary and mobile sources, control of criteria and air toxics, dispersion modeling, risk assessment, visibility analysis, odor analysis), supervisory functions and project management.
1990-1992	Engineering-Science, Inc. **Principal Engineer and Project Manager** in the air quality department. Responsibilities included permitting, tracking regulatory issues, technical analysis, and supervisory functions on numerous air, water, and hazardous waste projects. Responsibilities also include client and agency interfacing, project cost and schedule control, and reporting to internal and external upper management regarding project status.
1989-1990	Kinetics Technology International, Corp. **Development Engineer.** Involved in thermal engineering R&D and project work related to low-NOx ceramic radiant burners, fired heater NOx reduction, SCR design, and fired heater retrofitting.
1988-1989	Heat Transfer Research, Inc. **Research Engineer**. Involved in the design of fired heaters, heat exchangers, air coolers, and other non-fired equipment. Also did research in the area of heat exchanger tube vibrations.

EDUCATION

1984-1988	Ph.D., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.
1984	M. S., Mechanical Engineering, Caltech, Pasadena, CA.
1978-1983	B. Tech (Honors), Mechanical Engineering, Indian Institute of Technology (IIT) Kharagpur, India

TEACHING EXPERIENCE

Caltech

"Thermodynamics," Teaching Assistant, California Institute of Technology, 1983, 1987.

"Air Pollution Control," Teaching Assistant, California Institute of Technology, 1985.

"Caltech Secondary and High School Saturday Program," - taught various mathematics (algebra through calculus) and science (physics and chemistry) courses to high school students, 1983-1989.

"Heat Transfer," - taught this course in the Fall and Winter terms of 1994-1995 in the Division of Engineering and Applied Science.

“Thermodynamics and Heat Transfer,” Fall and Winter Terms of 1996-1997.

U.C. Riverside, Extension

"Toxic and Hazardous Air Contaminants," University of California Extension Program, Riverside, California. Various years since 1992.

"Prevention and Management of Accidental Air Emissions," University of California Extension Program, Riverside, California. Various years since 1992.

"Air Pollution Control Systems and Strategies," University of California Extension Program, Riverside, California, Summer 1992-93, Summer 1993-1994.

"Air Pollution Calculations," University of California Extension Program, Riverside, California, Fall 1993-94, Winter 1993-94, Fall 1994-95.

"Process Safety Management," University of California Extension Program, Riverside, California. Various years since 1992-2010.

"Process Safety Management," University of California Extension Program, Riverside, California, at SCAQMD, Spring 1993-94.

"Advanced Hazard Analysis - A Special Course for LEPCs," University of California Extension Program, Riverside, California, taught at San Diego, California, Spring 1993-1994.

“Advanced Hazardous Waste Management” University of California Extension Program, Riverside, California. 2005.

Loyola Marymount University

"Fundamentals of Air Pollution - Regulations, Controls and Engineering," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1993.

"Air Pollution Control," Loyola Marymount University, Dept. of Civil Engineering, Fall 1994.

“Environmental Risk Assessment,” Loyola Marymount University, Dept. of Civil Engineering. Various years since 1998.

“Hazardous Waste Remediation” Loyola Marymount University, Dept. of Civil Engineering. Various years since 2006.

University of Southern California

"Air Pollution Controls," University of Southern California, Dept. of Civil Engineering, Fall 1993, Fall 1994.

"Air Pollution Fundamentals," University of Southern California, Dept. of Civil Engineering, Winter 1994.

University of California, Los Angeles

"Air Pollution Fundamentals," University of California, Los Angeles, Dept. of Civil and Environmental Engineering, Spring 1994, Spring 1999, Spring 2000, Spring 2003, Spring 2006, Spring 2007, Spring 2008, Spring 2009.

International Programs

“Environmental Planning and Management,” 5 week program for visiting Chinese delegation, 1994.

“Environmental Planning and Management,” 1 day program for visiting Russian delegation, 1995.

“Air Pollution Planning and Management,” IEP, UCR, Spring 1996.

“Environmental Issues and Air Pollution,” IEP, UCR, October 1996.

PROFESSIONAL AFFILIATIONS AND HONORS

President of India Gold Medal, IIT Kharagpur, India, 1983.

Member of the Alternatives Assessment Committee of the Grand Canyon Visibility Transport Commission, established by the Clean Air Act Amendments of 1990, 1992-present.

American Society of Mechanical Engineers: Los Angeles Section Executive Committee, Heat Transfer Division, and Fuels and Combustion Technology Division, 1987-present.

Air and Waste Management Association, West Coast Section, 1989-present.

PROFESSIONAL CERTIFICATIONS

EIT, California (# XE088305), 1993.

REA I, California (#07438), 2000.

Certified Permitting Professional, South Coast AQMD (#C8320), since 1993.

QEP, Institute of Professional Environmental Practice, since 2000.

CEM, State of Nevada (#EM-1699). Expiration 10/07/2011.

PUBLICATIONS (PARTIAL LIST)

"Physical Properties and Oxidation Rates of Chars from Bituminous Coals," with Y.A. Levendis, R.C. Flagan and G.R. Gavalas, *Fuel*, **67**, 275-283 (1988).

"Char Combustion: Measurement and Analysis of Particle Temperature Histories," with R.C. Flagan, G.R. Gavalas and P.S. Northrop, *Comb. Sci. Tech.* **60**, 215-230 (1988).

"On the Combustion of Bituminous Coal Chars," PhD Thesis, California Institute of Technology (1988).

"Optical Pyrometry: A Powerful Tool for Coal Combustion Diagnostics," *J. Coal Quality*, **8**, 17-22 (1989).

"Post-Ignition Transients in the Combustion of Single Char Particles," with Y.A. Levendis, R.C.Flagan and G.R. Gavalas, *Fuel*, **68**, 849-855 (1989).

"A Model for Single Particle Combustion of Bituminous Coal Char." Proc. ASME National Heat Transfer Conference, Philadelphia, **HTD-Vol. 106**, 505-513 (1989).

"Discrete Simulation of Cenospheric Coal-Char Combustion," with R.C. Flagan and G.R.Gavalas, *Combust. Flame*, **77**, 337-346 (1989).

"Particle Measurements in Coal Combustion," with R.C. Flagan, in "**Combustion Measurements**" (ed. N. Chigier), Hemisphere Publishing Corp. (1991).

"Cross Linking in Pore Structures and Its Effect on Reactivity," with G.R. Gavalas in preparation.

"Natural Frequencies and Mode Shapes of Straight Tubes," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Optimal Tube Layouts for Kamui SL-Series Exchangers," with K. Ishihara, Proprietary Report for Kamui Company Limited, Tokyo, Japan (1990).

"HTRI Process Heater Conceptual Design," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Asymptotic Theory of Transonic Wind Tunnel Wall Interference," with N.D. Malmuth and others, Arnold Engineering Development Center, Air Force Systems Command, USAF (1990).

"Gas Radiation in a Fired Heater Convection Section," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1990).

"Heat Transfer and Pressure Drop in NTIW Heat Exchangers," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1991).

"NOx Control and Thermal Design," Thermal Engineering Tech Briefs, (1994).

“From Puchase of Landmark Environmental Insurance to Remediation: Case Study in Henderson, Nevada,” with Robin E. Bain and Jill Quillin, presented at the AQMA Annual Meeting, Florida, 2001.

“The Jones Act Contribution to Global Warming, Acid Rain and Toxic Air Contaminants,” with Charles W. Botsford, presented at the AQMA Annual Meeting, Florida, 2001.

PRESENTATIONS (PARTIAL LIST)

"Pore Structure and Combustion Kinetics - Interpretation of Single Particle Temperature-Time Histories," with P.S. Northrop, R.C. Flagan and G.R. Gavalas, presented at the AIChE Annual Meeting, New York (1987).

"Measurement of Temperature-Time Histories of Burning Single Coal Char Particles," with R.C. Flagan, presented at the American Flame Research Committee Fall International Symposium, Pittsburgh, (1988).

"Physical Characterization of a Cenospheric Coal Char Burned at High Temperatures," with R.C. Flagan and G.R. Gavalas, presented at the Fall Meeting of the Western States Section of the Combustion Institute, Laguna Beach, California (1988).

"Control of Nitrogen Oxide Emissions in Gas Fired Heaters - The Retrofit Experience," with G. P. Croce and R. Patel, presented at the International Conference on Environmental Control of Combustion Processes (Jointly sponsored by the American Flame Research Committee and the Japan Flame Research Committee), Honolulu, Hawaii (1991).

"Air Toxics - Past, Present and the Future," presented at the Joint AIChE/AAEE Breakfast Meeting at the AIChE 1991 Annual Meeting, Los Angeles, California, November 17-22 (1991).

"Air Toxics Emissions and Risk Impacts from Automobiles Using Reformulated Gasolines," presented at the Third Annual Current Issues in Air Toxics Conference, Sacramento, California, November 9-10 (1992).

"Air Toxics from Mobile Sources," presented at the Environmental Health Sciences (ESE) Seminar Series, UCLA, Los Angeles, California, November 12, (1992).

"Kilns, Ovens, and Dryers - Present and Future," presented at the Gas Company Air Quality Permit Assistance Seminar, Industry Hills Sheraton, California, November 20, (1992).

"The Design and Implementation of Vehicle Scrapping Programs," presented at the 86th Annual Meeting of the Air and Waste Management Association, Denver, Colorado, June 12, 1993.

"Air Quality Planning and Control in Beijing, China," presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, Ohio, June 19-24, 1994.

Annex A

Expert Litigation Support

1. Matters for which Dr. Sahu has have provided depositions and affidavits/expert reports include:

(a) Deposition on behalf of Rocky Mountain Steel Mills, Inc. located in Pueblo, Colorado – dealing with the manufacture of steel in mini-mills including methods of air pollution control and BACT in steel mini-mills and opacity issues at this steel mini-mill

(b) Affidavit for Rocky Mountain Steel Mills, Inc. located in Pueblo Colorado – dealing with the technical uncertainties associated with night-time opacity measurements in general and at this steel mini-mill.

(c) Expert reports and depositions (2/28/2002 and 3/1/2002; 12/2/2003 and 12/3/2003; 5/24/2004) on behalf of the US Department of Justice in connection with the Ohio Edison NSR Cases. *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (S.D. Ohio).

(d) Expert reports and depositions (5/23/2002 and 5/24/2002) on behalf of the US Department of Justice in connection with the Illinois Power NSR Case. *United States v. Illinois Power Co., et al.*, 99-833-MJR (S.D. Ill.).

(e) Expert reports and depositions (11/25/2002 and 11/26/2002) on behalf of the US Department of Justice in connection with the Duke Power NSR Case. *United States, et al. v. Duke Energy Corp.*, 1:00-CV-1262 (M.D.N.C.).

(f) Expert reports and depositions (10/6/2004 and 10/7/2004; 7/10/2006) on behalf of the US Department of Justice in connection with the American Electric Power NSR Cases. *United States, et al. v. American Electric Power Service Corp., et al.*, C2-99-1182, C2-99-1250 (S.D. Ohio).

(g) Affidavit (March 2005) on behalf of the Minnesota Center for Environmental Advocacy and others in the matter of the Application of Heron Lake BioEnergy LLC to construct and operate an ethanol production facility – submitted to the Minnesota Pollution Control Agency.

(h) Expert reports and depositions (10/31/2005 and 11/1/2005) on behalf of the US Department of Justice in connection with the East Kentucky Power Cooperative NSR Case. *United States v. East Kentucky Power Cooperative, Inc.*, 5:04-cv-00034-KSF (E.D. KY).

(i) Deposition (10/20/2005) on behalf of the US Department of Justice in connection with the Cinergy NSR Case. *United States, et* al. *v. Cinergy Corp., et al.*, IP 99-1693-C-M/S (S.D. Ind.).

(j) Affidavits and deposition on behalf of Basic Management Inc. (BMI) Companies in connection with the BMI vs. USA remediation cost recovery Case.

(k) Expert report on behalf of Penn Future and others in the Cambria Coke plant permit challenge in Pennsylvania.

(l) Expert report on behalf of the Appalachian Center for the Economy and the Environment and others in the Western Greenbrier permit challenge in West Virginia.

(m) Expert report, deposition (via telephone on January 26, 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) in the Thompson River Cogeneration LLC Permit No. 3175-04 challenge.

(n) Expert report and deposition (2/2/07) on behalf of the Texas Clean Air Cities Coalition at the Texas State Office of Administrative Hearings (SOAH) in the matter of the permit challenges to TXU Project Apollo's eight new proposed PRB-fired PC boilers located at seven TX sites.

(o) Expert testimony (July 2007) on behalf of the Izaak Walton League of America and others in connection with the acquisition of power by Xcel Energy from the proposed Gascoyne Power Plant – at the State of Minnesota, Office of Administrative Hearings for the Minnesota PUC (MPUC No. E002/CN-06-1518; OAH No. 12-2500-17857-2).

(p) Affidavit (July 2007) Comments on the Big Cajun I Draft Permit on behalf of the Sierra Club – submitted to the Louisiana DEQ.

(q) Expert reports and deposition (12/13/2007) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (W.D. Pennsylvania).

(r) Expert reports and pre-filed testimony before the Utah Air Quality Board on behalf of Sierra Club in the Sevier Power Plant permit challenge.

(s) Expert reports and deposition (October 2007) on behalf of MTD Products Inc., in connection with General Power Products, LLC v MTD Products Inc., 1:06 CVA 0143 (S.D. Ohio, Western Division)

(t) Experts report and deposition (June 2008) on behalf of Sierra Club and others in the matter of permit challenges (Title V: 28.0801-29 and PSD: 28.0803-PSD) for the Big Stone II unit, proposed to be located near Milbank, South Dakota.

(u) Expert reports, affidavit, and deposition (August 15, 2008) on behalf of Earthjustice in the matter of air permit challenge (CT-4631) for the Basin Electric Dry Fork station, under construction near Gillette, Wyoming before the Environmental Quality Council of the State of Wyoming.

(v) Affidavit/Declaration and Expert Report on behalf of NRDC and the Southern Environmental Law Center in the matter of the air permit challenge for Duke Cliffside Unit 6, under construction in North Carolina.

(w) Dominion Wise County MACT Declaration (August 2008)

(x) Expert Report on behalf of Sierra Club for the Green Energy Resource Recovery Project, MACT Analysis (June 13, 2008).

(y) Expert Report on behalf of Sierra Club and the Environmental Integrity Project in the matter of the air permit challenge for NRG Limestone's proposed Unit 3 in Texas (February 2009).

(z) Expert Report and deposition on behalf of MTD Products, Inc., in the matter of Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al. (June 2009, July 2009).

(aa) Expert Report on behalf of Sierra Club and the Southern Environmental Law Center in the matter of the air permit challenge for Santee Cooper's proposed Pee Dee plant in South Carolina (August 2009).

(bb) Statements (May 2008 and September 2009) on behalf of the Minnesota Center for Environmental Advocacy to the Minnesota Pollution Control Agency in the matter of the Minnesota Haze State Implementation Plans.

(cc) Expert Report (August 2009) and Deposition (October 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(dd) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Coleto Creek coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (October 2009).

(ee) Expert Report, Rebuttal Report (September 2009) and Deposition (October 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

(ff) Expert report (December 2009), Rebuttal reports (May 2010 and June 2010) and depositions (June 2010) on behalf of the US Department of Justice in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).

(gg) Prefiled testimony (October 2009) and Deposition (December 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(hh) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Tenaska coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (April 2010).

(ii) Written Direct Testimony (July 2010) and Written Rebuttal Testimony (August 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(jj) Expert report (August 2010) and Rebuttal Expert Report (October 2010) on behalf of the US Department of Justice in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

(kk) Declaration (August 2010) on behalf of the US EPA and US Department of Justice in the matter of DTE Energy Company, Detroit, MI (Monroe Unit 2).

(ll) Expert Report and Deposition (August 2010) as well as Affidavit (September 2010) on behalf of Kentucky Waterways Alliance, Sierra Club, and Valley Watch in the matter of challenges to the NPDES permit issued for the Trimble County power plant by the Kentucky Energy and Environment Cabinet to Louisville Gas and Electric, File No. DOW-41106-047.

(mm) Expert Report (August 2010) and Rebuttal Expert Report (September 2010) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

(nn) Written Direct Expert Testimony (August 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(oo) Deposition (August 2010) on behalf of Environmental Defense, in the matter of the remanded permit challenge to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(pp) Expert Report, Supplemental/Rebuttal Expert Report, and Declarations (October 2010) on behalf of New Mexico Environment Department (Plaintiff-Intervenor), Grand Canyon Trust and Sierra Club (Plaintiffs) in the matter of Public Service Company of New Mexico (PNM)'s Mercury Report for the San Juan Generating Station, CIVIL NO. 1:02-CV-0552 BB/ATC (ACE). US District Court for the District of New Mexico.

(qq) Comment Report (October 2010) on the Draft Permit Issued by the Kansas DHE to Sunflower Electric for Holcomb Unit 2. Prepared on behalf of the Sierra Club and Earthjustice.

(rr) Expert Report (October 2010) and Rebuttal Expert Report (November 2010) (BART Determinations for PSCo Hayden and CSU Martin Drake units) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

(ss) Expert Report (November 2010) (BART Determinations for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

(tt) Comment Report (December 2010) on the Pennsylvania Department of Environmental Protection (PADEP)'s Proposal to grant Plan Approval for the Wellington Green Energy Resource Recovery Facility on behalf of the Chesapeake Bay Foundation, Group Against Smog and Pollution (GASP), National Park Conservation Association (NPCA), and the Sierra Club.

(uu) Written Expert Testimony (January 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

2. Occasions where Dr. Sahu has provided oral testimony <u>at trial or in similar proceedings</u> include the following:

(vv) In February, 2002, provided expert witness testimony on emissions data on behalf of Rocky Mountain Steel Mills, Inc. in Denver District Court.

(ww) In February 2003, provided expert witness testimony on regulatory framework and emissions calculation methodology issues on behalf of the US Department of Justice in the Ohio Edison NSR Case in the US District Court for the Southern District of Ohio.

(xx) In June 2003, provided expert witness testimony on regulatory framework, emissions calculation methodology, and emissions calculations on behalf of the US Department of Justice in the Illinois Power NSR Case in the US District Court for the Southern District of Illinois.

(yy) In August 2006, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Western Greenbrier) on behalf of the Appalachian Center for the Economy and the Environment in West Virginia.

(zz) In May 2007, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Thompson River Cogeneration) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) before the Montana Board of Environmental Review.

(aaa) In October 2007, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Sevier Power Plant) on behalf of the Sierra Club before the Utah Air Quality Board.

(bbb) In August 2008, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Big Stone Unit II) on behalf of the Sierra Club and Clean Water before the South Dakota Board of Minerals and the Environment.

(ccc) In February 2009, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Santee Cooper Pee Dee units) on behalf of the Sierra Club and the Southern Environmental Law Center before the South Carolina Board of Health and Environmental Control.

(ddd) In February 2009, provided expert witness testimony regarding power plant emissions, BACT issues and MACT issues on a permit challenge (NRG Limestone Unit 3) on behalf of the Sierra Club and the Environmental Integrity Project before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(eee) In November 2009, provided expert witness testimony regarding power plant emissions, BACT issues and MACT issues on a permit challenge (Las Brisas Energy Center) on behalf of the Environmental Defense Fund before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(fff) In February 2010, provided expert witness testimony regarding power plant emissions, BACT issues and MACT issues on a permit challenge (White Stallion Energy Center) on behalf of the Environmental Defense Fund before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(ggg) In September 2010 provided oral trial testimony on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, State of Maryland, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case in US District Court in the Western District of Pennsylvania. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (W.D. Pennsylvania).

(hhh) Oral Direct and Rebuttal Expert Testimony (September 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(iii) Oral Testimony (September 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(jjj) Oral Testimony (October 2010) regarding mercury and total PM/PM10 emissions and other issues on a remanded permit challenge (Las Brisas Energy Center) on behalf of the Environmental Defense Fund before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(kkk) Oral Testimony (November 2010) regarding BART for PSCo Hayden, CSU Martin Drake units before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(lll) Oral Testimony (December 2010) regarding BART for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(mmm) Deposition (December 2010) on behalf of the US Department of Justice in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

(nnn) Deposition (February 2011) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

(ooo) Oral Expert Testimony (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

March 11, 2005

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DEPT ENVIRONMENTAL PROTECTION

Mr. Thomas Joseph
Pennsylvania Department of Environmental Protection
Southwest Regional Office
400 Waterfront Drive
Pittsburgh, PA 15222-4754

Re: Robinson Power Company (Beech Hollow) Waste-Coal-Fired Power Generation Facility in Washington County, Pennsylvania

Dear Mr. Joseph:

Thank you for the opportunity to review the Commonwealth of Pennsylvania's proposed prevention of significant deterioration (PSD) and nonattainment new source review (NSR) permit for the Robinson Power Company's proposed Waste-Coal-Fired Power Generation Facility in Washington County, Pennsylvania. We understand that the proposed facility, will consist of, in part:

1. Circulating fluidized-bed boiler (CFB) powering a 272 megawatt steam turbine generator;
2. 400 foot exhaust stack;
3. Cooling tower;
4. Emergency generator;
5. Firewater pump;
6. Material handling, preparation and storage system for coal, limestone, and ash

The proposed facility is to be located in Washington County which is currently designated as nonattainment for the national ambient air quality standards (NAAQS) for ozone; will be formally designated as nonattainment for particulate matter (PM2.5) on April 5, 2005; and, is classified as attainment for sulfur dioxide (SO2), nitrogen oxides (NO2), carbon monoxide (CO) and lead (Pb). It should be noted that air quality dispersion modeling supporting the application indicates that there are modeled exceedances of the NAAQS for SO2 in the area. Further, the project is predicted to contribute to adverse air quality impacts in nearby Class I air quality areas. The Clean Air Act establishes the criteria for Class I area designation and requires that these areas be provided additional protections for air quality, including visibility. The proposed project has been identified to have impacts or potential impacts to the Dolly Sods and Otter Creek Wilderness Areas in West Virginia and the Shenandoah National Park in Virginia.

Because of the NAAQS classifications, the provisions of PSD and nonattainment NSR apply to the project for the relevant pollutants. EPA is offering its comments regarding the proposed permit and permit application pursuant to the Commonwealth's implementation of its federally-approved PSD and nonattainment NSR regulations. As part of those regulations, the applicant and Pennsylvania Department of Environmental Protection (PADEP) are to determine, among other things, the appropriate pollution control technologies and strategies to minimize the air quality impacts from the project and to perform air quality dispersion modeling analyses to ensure that the project does not cause or contribute to adverse air quality impacts. The results of the technology review and modeling analyses are to be memorialized by enforceable permit conditions.

Comment 1: General Comments regarding BACT/LAER Determinations

The PADEP's technical review memorandum (TRM) provided in support of the proposed plan approval relates information provided by the applicant regarding the best available control technology (BACT) and lowest achievable emission rate (LAER) technology assessments for the project. For the BACT analyses, PADEP is to consider both technical and economic feasibility of various pollution control technologies and strategies when making its determinations regarding the applicable pollutant-specific BACT for the proposed facility. The LAER determinations are similar, however, economic factors are not considered because LAER is applicable in areas that are not currently achieving the NAAQS for the given pollutant. The applicant and PADEP have concluded that the proposed facility can be designed and operated in only one fashion, with all other control technologies determined to be technically infeasible. Because all other technologies have been deemed technically infeasible, the applicant and PADEP did not pursue an examination of the cost effectiveness of any of the potential control options. EPA believes that the justifications provided by the applicant and PADEP in support of their conclusions on technical infeasibility are under-developed and insufficient.

Currently PADEP is evaluating two waste-coal-fired boiler projects in addition to the Robinson Power project. The Greene Energy project is proposed for Greene County, Pennsylvania and the River Hill project is proposed for Clearfield County, Pennsylvania. We urge the Southwest Regional office to confer with the Northcentral Regional Office regarding the rigor of analyses that office is seeking for the River Hill project. On a number of occasions over the past few months, the Northcentral Office has sought the type of additional technical and economic analyses from the River Hill representatives that EPA is seeking for the Robinson Power project. EPA believes it is important that PADEP employ a consistent approach when evaluating the three similar projects. We will identify our specific concerns below.

Comment 2: BACT Determination for SO2

The proposed permit indicates that the BACT determination for SO2 is the operation of the circulated fluidized bed (CFB) boiler with limestone injection capable of achieving close to 97 percent control of SO2 emissions. PADEP's TRM and the application discuss other potential control technologies, however, each are dismissed as being technically infeasible. EPA believes that the discussion pertaining to pre-combustion coal cleaning is not fully supported and contends that opportunities exist to technically and economically clean the waste coal prior to combustion in the CFB. The benefits of coal cleaning are plentiful. By reducing the amount of elemental sulfur being introduced into the CFB, less sulfur dioxide is emitted from the facility. Coal cleaning is also effective at reducing the ash content of the incoming fuel stream, which will reduce the operational burden on the CFB, reduce particulate matter emissions, and limit the post-combustion ash-handling and disposal requirements of the facility. Further, pre-combustion coal cleaning can reduce the amount of trace element heavy metals that are burned in the CFB and released into the air.

EPA is seeking further justification from PADEP in support of its claim that coal cleaning is not technically feasibility. In Enclosure 1 to this letter, we are providing the results of our analysis of the cost effectiveness of one type of coal cleaning for this project. Further, we believe it would be prudent for PADEP to examine the cost effectiveness of various types of coal cleaning, including wet and dry separation, magnetic separation, and froth flotation. It should be noted that any assumptions such as the sulfur content of the waste fuel, BTU content, fuel feed rates, etc. that are relied upon in any cost effectiveness analyses performed for this project would need to be codified as enforceable conditions in the permit if its determined that coal cleaning is not cost effective. This is necessary because changes in these variables significantly affect the cost effectiveness calculations. For example, if the sulfur content of the fuel stream increases above the 1.8 percent identified in the application, the cost effectiveness of control options will improve (i.e. the cost per ton of pollution avoided would decrease making the control more cost effective.)

EPA understands that PADEP, and particularly the Southwest Regional Office, has extensive knowledge and understanding of coal cleaning and preparation operations. As recently as last year, the Southwest Regional Office issued a permit to the Rosebud Mining Company in Armstrong County that allowed the company to upgrade its wet and dry coal clean operations to clean high ash and high sulfur coal originating from the Company's high ash coal stockpile. Likewise, the Office issued a permit to the Seward Generating Station for its waste-coal-fired CFB project a couple of years ago. However, the Seward CFB project netted out of PSD for SO2, therefore, the project was not required to perform a BACT analysis. Other regional offices of PADEP have issued PSD permits to CFB projects, such as the Gilberton Power and the Panther Creek Partners Power Generation facilities, both examples of waste-coal-fired CFB facilities that employ pre-combustion coal cleaning. The Gilberton Power fluidized bed combustion cogeneration facility, located in Schuylkill County, Pennsylvania cleans anthracite culm (coal refuse) prior to combustion using gravity separation techniques in order reduce the ash content of the fuel from 70 percent to as low as 40 percent prior. Along with the beneficial reduction in ash, the sulfur content of the fuel is reduced. The Panther Creek facility in Carbon County also burns culm which is cleaned using heavy-medium separation to reduce ash and sulfur prior to combustion. This facility employees two circulating fluidized boilers. The Panther Creek Partners unit has a permit limit of 0.129 lb/MMBTU of SO2. The proposed emission limit for the Robinson Power project is 0.234 lbs/MMBTU of SO2. (The applicant proposed an emission limit of 0.26 lbs/MMBTU of SO2 in its application.) EPA would also like to offer that it recently received an application for a bituminous waste-coal fired CFB in Greenbrier County, West Virginia which proposes an SO2 emission limit of 0.15 lbs/MMBTU. The application indicates that the waste coal will have a sulfur content of approximately 1.1 percent compared to the 1.8 percent estimated by Robinson Power.

EPA also wants to take the opportunity to clarify that it is suggesting an objective assessment of the efficacy of coal cleaning. The Agency is not affirmatively asserting that the proposed project could install coal cleaning operations that produce a fuel stream that could be used in a different style of combustion device, such as a pulverized coal-fired boiler. We also recognize that PADEP is strongly supporting the potential collateral benefits of the proposed project with respect to reclamation of the coal waste disposal area and the economic benefits to the local area. With regard to the former, we support the Department's desire to address the long-standing impacts to the aquatic environment from the waste coal pile. EPA simply wants to ensure that addressing those issues does not exacerbate existing air quality concerns in the region and their associated human health impacts. We believe coal cleaning can fit into this strategy and can provide additional air quality benefits and economic benefits attributable to reducing the cost of handling and transporting (either by conveyance or truck) ash-laden fuel and combustion waste products. The addition of coal cleaning operations could also add to the already impressive array of regional economic benefits identified by the applicant and PADEP by increasing the construction and operations labor force associated with the project. With all of that said, EPA must ultimately examine the project with respect to the PSD and nonattainment NSR regulations which focus directly on the air quality impact of a given project.

Comment 3: LAER Analysis for NOx

The proposed permit indicates that the LAER determination for NOx is the installation of selective noncatalytic reduction (SNCR) technology as a post-combustion control device for the CFB achieving approximately 75 percent control of NOx emissions. The TRM and application indicate that SNCR is the only technically feasible control option available for the project. Again, EPA believes that the justification provided does not adequately support the conclusion that a better performing control device, selective catalytic reduction (SCR), is not technically feasible. Selective catalytic reduction is capable of achieve upwards to 90 percent NOx control or better. The TRM and application claims that employment of SCR technology at CFB installations is problematic due to high dust issues related to the CFB and the temperature requirements necessary to effectively operate SCR technology. The TRM broadly states that energy requirements for reheating the flue gas stream after the dust control device would render the project infeasible and that the NOx emissions attributable to such energy requirements would negate the potential benefits of SCR over SNCR. A full articulation of the energy requirements and the associated NOx disbenefits must be provided to support these claims. For LAER determinations, the costs associated with the additional energy requirements would not be a consideration. Again, the purpose of the LAER determination is to determine the lowest emission rate the facility can achieve regardless of cost, acknowledging that the source is being located in a nonattainment area. It is also important to evaluate how coal cleaning and its attendant reduction in ash feed to the CFB would affect PM emissions from the baghouse and the "high dust" conditions.

Comment 4: BACT/LAER/BAT Determinations for Emergency Generator, Firewater Pump and Dryer

The proposed plan approval contains emission imitations only for particulate matter for the baghouse associated with the dryer. The TRM indicates expected unit-specific emissions from the emergency generator and firewater pump, however, the proposed permit does not appear to reflect those unit specific emission limits. The proposed permit should establish unit-specific emission limits for these units for all relevant pollutants and codify the operating restrictions that form the basis for the predicted annual emissions (e.g. hours of operation). We appreciate that the potential emissions from these units are expected to be low, however, the permit must contain practically enforceable limits to ensure that is the case. Likewise, the TRM and the application do not discuss the BACT/LAER/BAT determinations for these units, except for PM from the dryer.

Comment 5: Mercury Emissions from the CFB and Regulatory Requirements

Until such time that EPA finalizes its regulatory approach for addressing mercury emissions from coal-fired utility units, proposed utility plants are obligated by section 112(g) of the Clean Air Act and its implementing regulations at 40 CFR 63.43 to perform a case-by-case maximum achievable control technology (MACT) determination. Forty CFR 63.43(d)(4) requires the permitting authority to consider any relevant EPA-proposed MACT rule when making such a determination. On January 30, 2004 EPA proposed MACT standards for mercury emissions from coal-fired electric utility units. The proposal includes standards for waste-coal-fired units and continuous emissions monitoring. At the same time, EPA also proposed a market-based rule to regulate mercury emissions from coal-fired utility units. It should be noted that under either of the regulatory options proposed on January 30, 2004, EPA would establish mercury limits for new sources (applicable to all sources commencing construction after January 30, 2004) and continuous emissions monitoring systems (CEMS) for mercury.

EPA expects to finalize one of the proposed regulatory options by March 15, 2005, with a future effective date. Since final action has not occurred and the outcome of such action is unknown at this time, PADEP and the applicant are not relieved of the requirements of section 112(g). Considering the substantial public interest in the proposed rulemaking and the potential for litigation on whatever rule proposal EPA proposes, it may be prudent to fulfill the obligation of 112(g) at this time.

A case-by-case MACT determination has not been performed by the applicant or PADEP, rather an examination of mercury control options was performed by the state under its best available technology (BAT) provisions. EPA believes the brief discussion provided in the documents regarding potential mercury controls does not represent an adequate case-by-case MACT determination. However, the proposed permit does establish an mercury emission limitation of 0.113 lbs-Hg/Trillion BTU which appears generally consistent with the emission limitations for new waste coal utility units in both of the proposed rules. It may prove necessary to perform a more rigorous technical and economic feasibility analysis of mercury controls, particularly if the limit in the proposed permit is changed or if there are significant changes in EPA's rules that are expected to be finalized shortly. It should be noted that PADEP has requested this type of information from applicants for similar facilities, namely the River Hill project.

Regarding mercury CEMS, EPA considers mercury CEMS to be available and proposed their use in both rules. EPA is strongly encouraging the installation and operation of mercury CEMS for use by newly constructed facilities that will be subject to whichever version of the mercury rule prevails.

Comment 6: Particulate Matter Compliance Monitoring

The proposed plan approval requires annual stack testing to assure compliance with the particulate matter emission limits from the CFB and its associated fabric-filter baghouse. In light of the evolution of CEMS systems for particulate matter, EPA is strongly urging the requirement to install and operate a particulate matter CEMS at the proposed facility. Currently, there are several facilities that operate PM CEMS and have demonstrated that the systems are reliable and accurate. These are 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. It is fair to assume that the state of technology for PM CEMS will be even further evolved by the time the proposed Robinson Power facility begins operation. Further, the facility will be required to establish a compliance assurance monitoring plan (CAM) as part of its title V operating permit and the federal CAM regulations strongly encourage reliance on continuous monitoring systems as a means for assuring compliance. Also, the upcoming redesignation of the area to nonattainment for PM2.5 suggests that more timely and accurate data regarding PM emissions from the proposed facility would be important information.

Comment 7: Air Quality Dispersion Modeling

The TRM for the proposed permit does not provide a discussion of PADEP's analysis of the air quality dispersion modeling submitted in support of the application. Enclosure 2 to this letter presents EPA's comments regarding the modeling analyses provided to the Agency as part of the proposed permit announcement. We understand that modeling analyses related to the project continue to be developed. Clearly, it will be necessary for EPA and the public to have an opportunity to review and comment on all of the modeling information that is relied upon to establish permit requirements.

Comment 8: Mitigation of Air Quality Impacts

Related to the above discussion, certain aspects of the modeling analyses indicate that the proposed project must mitigate portions of its emissions in order to address identified adverse air quality impacts in affected Class I areas. The proposed permit does not expressly identify the degree of mitigation that is necessary, nor the requirement to ensure that such mitigation measures are achieved prior commencement of source operation. The proposed permit must be revised to address these issues. As above, we understand that all of the modeling related to determining the full impacts on air quality have not been completed. Again, adequate opportunity to thoroughly review and comment on those analyses must be provided.

If you have any questions or comments, please contact me at 215 814-2196 or Paul Wentworth of my staff at 215 814-2183.

Sincerely,

David Campbell, Chief
Permits and Technical Assessment Branch

cc: John Slade, PADEP Central Office

Enclosures (2)

ENCLOSURE 1

Cost Effectiveness Analysis for Coal Cleaning using Dry Gravity Separation (e.g. Air Jigging) to Reduce Sulfur Dioxide Emissions

The following represents an analysis of the cost effectiveness of pre-combustion coal cleaning using the input presumptions provided in the Robinson Power Project application with respect to fuel composition, thermal requirements, feed rates, CFB SO2 control efficiency, etc. In preparing the analysis, EPA followed the methodologies prescribed in "OAQPS Control Cost Manual," U.S. Environmental Protection Agency, Research Triangle Park, NC. November 1989. EPA developed the cost and operational data used to support the economic analysis through literature research and consultation with equipment vendors. Since no cost effectiveness information was provided by the applicant or PADEP regarding pre-combustion control option or operation of the CFB, EPA was unable to consider that information in the cost analysis.

In performing this analysis, EPA only examined the cost of coal cleaning using air jigging technology. As stated in the above comment letter, we have charged PADEP and the applicant with exploring the full range of coal cleaning options. Table 1 below represents a summary of the cost effectiveness of pre-combustion coal cleaning and its affect on the resultant sulfur content of the cleaned coal. As the sulfur content of the fuel feed decreases, the potential for sulfur dioxide formation in the CFB decreases proportionally at a 1:2 ratio. The table below presents the cost effectiveness of air jigging on sulfur (thus, sulfur dioxide) removal based on removal efficiencies ranging from 30 to 50 percent sulfur removal in the fuel feed. Discussions with vendors and our own independent research indicate that such performance has been demonstrated and is reasonable.

Table 1: COAL CLEANING COST EFFECTIVENESS

Assumptions:
Annual Tons of SO2 Formed Without Coal Cleaning: 105,148 tons/year
Percent Sulfur Content Coal: 1.8%
[Above information derived from permit application - "Guarantee Basis" scenario]

Coal Cleaning Sulfur Dioxide Removal Efficiency*	Post-Cleaning Potential SO2 [tons/yr]	SO2 Avoided by Cleaning [tons/yr]	Cost Effectiveness of SO2 Removal [$/ton SO2 removed]
0%	105,148	0	n/a
30%	73,604	31,544	$102
40%	63,089	42,059	$79
50%	52,574	52,574	$61

*Assumes 100% conversion of sulfur in fuel to SO2 upon combustion

It should be noted that the costs presented above do not reflect additional benefits that may be realized due to reduced pre-combustion fuel transport, reduced post-combustion ash handling and disposal costs, savings attributable to reducing already identified SO2 air quality impact mitigation expenses, reduced operational costs related to purchase of supplemental run-of-mine coal, and reduced costs associated with decreased limestone injection requirements. EPA also recognizes that it may not have accounted for all of the costs associated with coal cleaning operations and welcomes feedback on those costs. Table 2 below reflects the full economic analysis in support of the summary data provided in Table 1. (Table 2 only presents data for 30 percent sulfur removal, the costs for increased removal efficiencies are directly proportional.)

Table 2: Cost Effectiveness Analysis of Coal Cleaning	
TOTAL EQUIPMENT COST (TEC)	**$3,098,434**
DIRECT INSTALLATION COSTS	
Freight (5% of TEC)	$154,922
Sales Tax	n\a
Instrumentation Cost (10 of TEC)	$309,843
TOTAL DIRECT INSTALLATION COSTS	**$464,765**
TOTAL DIRECT COST (TDC)	**$3,563,199**
INDIRECT INSTALLATION COSTS	
General Facilities (5% of TDC)	$178,160
Engineering and Home Office Fees (10% of TDC)	$356,320
Process Contingency (5% of TDC)	$178,160
TOTAL INDIRECT INSTALLATION COSTS	**$712,640**
Project Contingency (15% of (TDC + Total Indirect Installation Costs)	$641,376
TOTAL PLANT COSTS (TPC)	$4,917,215
Preproduction Cost (2% of TDC)	$98,344
TOTAL CAPITAL INVESTMENT (TCI)	**$5,015,559**
Maintenance Costs	$1,428,066
Overhead (60% of Maintenance Costs)	$856,840
Property Tax (1% of TCI)	$50,156
Insurance (1% of TCI)	$50,156
Administration(2% of TCI)	$100,311
TOTAL ANNUAL COSTS	**$2,485,527.96**
Capital recovery factor : Equipment Life 10 yrs, Interest rate 8.0 %	0.15
TOTAL ANNUALIZED CAPITAL	**$747,318.30**
TOTAL ANNUALIZED COST	**$3,232,846**
Total Tons of SO2 removed	**31,544**
Cost Effectiveness = total annualized cost/Total Annual Tons of SO2 Removed, $/Ton	**$102**

Table 2: Continued.

Assumptions:

Boiler Specifications

Max Hourly Heat Input mmBtu/Hr	*2770*
Max Hourly Coal use TPH 1/4470 x 2770 x 10^{+3} x1/2000 = 309.8 Tons per hour	***309.8***
Fuel Specs	
Btu Content Btu/Lb	*4,470.00*
Sulfur Content Lb S/Lb Coal	*0.18*
Ash Content, Lb Ash/Lb Coal	*0.42*
Cost: Air Jig Portion of Coal Cleaning Plant	
Capital Cost	
$10,000 per Ton/Hr x 310 TPH Consists of (4) 4x8 Air Jigs, W/ Structural members baghouse, electrical components	*$3,098,434*
Operation and Maintenance (annually, 8760 hrs)	
Power Cost & Maintenance Parts Costs $0.50/Ton	*$1,371,816*
Operator @ 45,000 /yr	*$45,000*
Supervision @ 11,250	*$11,250*
Total O&M	*$1,428,066*
Total Capital	***$3,098,434***
Total O&M	***$1,428,066***

Avoided Sulfur Dioxide Creation by Air Jig

Lbs/hr of SO2 formed (From Application, Appendix A, page 2) in application = 24006.42 lbs/hr

Annual Tons of Potentially Uncontrolled SO2 =
= 24,006.46 lbs/Hr x 8760 Hr x 1/2000 tons/Lb
= 105,148.29 Tons of Uncontrolled SO2

105,148.29 Tons, Potential Emissions Uncontrolled SO2 x .30

=31,544 tons of Potential SO2 avoided

Notes
a. 1979 DOE Data shows 30 % separation performance for air Jig

b. Report 49-1, September 1994 Prepared by:
Commonwealth of Virginia Department of Environmental Quality Office of Pollution Prevention Indicates in section 4.4.3.3, the Total sulfur reduction % on average in the US from Coal cleaning is 33%

The economic analyses presented above evaluates the cost effectiveness of coal cleaning as a primary means of sulfur dioxide reduction. EPA also examined the relative incremental cost of adding coal cleaning to a sulfur dioxide control strategy that presumes operation of the CFB with limestone injection as the primary means for sulfur dioxide control. The incremental cost effectiveness analysis essentially compares the cost of cost effectiveness of operating the CFB without precombustion coal cleaning to operation of the CFB with coal cleaning. When examining the incremental cost effectiveness of additional pollution control strategies, the values inherently increase due to the diminishing quantities of pollution to control. In comparison to direct cost effectiveness values, the acceptable burden for incremental cost effectiveness is considerably greater.

Table 3 presents a comparative summary of the incremental cost effectiveness of coal cleaning relative to CFB with limestone injection as the primary control. As mentioned above, the table does not account for additional potential savings attributable coal cleaning, and specifically does not reflect the decreased operational cost of limestone injection, since that data was not provided in the application.

Table 3: COAL CLEANING INCREMENTAL COST EFFECTIVENESS

Assumptions:
Annual Tons of SO2 Formed Without Coal Cleaning: 105,148 tons/year
Percent Sulfur Content Coal: 1.8%
S02 Removal from CFB with limestone injection assumed to achieve 97% control efficiency
[Above information derived from permit application - "Guarantee Basis" scenario]

Coal Cleaning Sulfur Dioxide Removal Efficiency*	Post-Cleaning Potential SO2 [tons/yr]	Post-Combustion SO2 Emission (after 97% control) [tons/yr]	Incremental (Additional) SO2 Reduction From Coal Cleaning [tons/yr]	Incremental Cost Effectiveness of SO2 Removal [$/ton SO2 removed]**
0%	105,148	3,154	0	n/a
30%	73,604	2,208	946	$3,417
40%	63,089	1,893	1,261	$2,564
50%	52,574	1,577	1,577	$2,050

*Assumes 100% conversion of sulfur in fuel to SO2 upon combustion
** Assumes $3,232,846 total annualized cost from Table 2 analysis

ENCLOSURE 2

EPA Region III's Comments on the Air Quality Modeling Analyses for the Proposed Robinson Power Project

These following comments are based upon a review of the material received. Since no input and output data files to support an independent verification of the modeling were provided, nor was there a discussion of PADEP's review, the comments can only reflect the acceptability of the applicant's conclusions and the stated methods of deriving them.

June 14, 2004 Modeling Analysis:

2.0 Model Parameters

Meteorological data from Greater Pittsburgh Airport for the years 1987, 1989, 1990, 1992 and 1993 were used. The Guideline on Air Quality Models (GAQM) specifies that representative meteorological data from the most recent five consecutive years is preferred. The modeling protocol of September 15, 2003 indicates that five years of data will be used and that data from 1987 through 1995 is available. The protocol further states that a five year period will be selected that meets U. S. EPA data completeness. First, there must be a demonstration and determination, by PADEP, that Greater Pittsburgh Airport data is representative. Then there must be a discussion and explanation of the years of data selected for analysis. Since the preferred data base would seem to be 1991 through 1995 (the most recent five consecutive years available) it could be concluded that the missing years would yield undesired modeling results.

2.3 Emission Sources

An inventory of increment consuming sources is presented in Table 2. Inventories of allowable emissions of SO2 and PM10 are presented in Tables 3 and 4, respectively. Each table includes the emission rate, in grams per second, which were modeled to evaluate PSD increment consumption and NAAQS compliance. The GAQM specifies that the modeled emission rates should be determined as the product of emission limit (such as lb/mmBtu), operating level (such as mmBtu/hr) and operating factor (such as hours per day). Unless the source's permit specifies an emission limit in terms of grams per second there is no other way to verify that the modeled emission rates are consistent with the emission limits. The emission rates listed in Tables 2, 3 and 4 must be calculated as specified by the GAQM and the calculations made available.

In Table 2, the SO2 emissions of the Robinson Pwr Boiler Main Stack are reported to be 13.394 grams/sec for 3-hour increment consumption and 91.26 grams/sec for 24-hour increment consumption. The allowable emission rate for 24-hours cannot be greater than the allowable emission rate for 3-hours. The same impossible emission rates are reported in Table 3 for the NAAQS analysis.

It is not understandable that Mon Valley Cogen (30-306-001) could be an SO2 increment consuming source, with 30.38 grams per sec of emissions and not be listed in Table 3 as a source to model for NAAQS compliance.

The emission inventories should include all sources for which a complete application has been received even if those sources have not received a permit. The failure to include sources such as the proposed Greene Energy and Cambria Coke facilities would make this analysis incomplete.

2.4 Background Concentrations

Notwithstanding the fact that monitoring to establish background is required by the Clean Air Act, the PSD Regulations, and EPA Guidance the background used is derived from state surveillance monitors. Furthermore, although there is no prescribed way to determine background, the method used here of adopting the average from a network of monitors would be one of the least desirable. The background used to satisfy the spirit of the statutory and regulatory requirement should represent the location of the maximum impact from the proposed source and the location of the maximum impact of the proposed source in conjunction with all other sources. While the background values used for this analysis do not appear to be unrealistic, the background should be determined in a better way.

3.0 Modeling Results

The sulfur dioxide modeling analysis indicates that there are nine receptors where the annual NAAQS is violated. Although Robinson Power does not have a significant contribution to any of the violations the State must, in a timely manner, demonstrate to the Administrator that the SIP is adequate to protect the NAAQS.

November 23, 2004, Class I Modeling Results and Mitigation Analysis:

Robinson Power's emissions, even subtracting the proposed mitigation emissions, show a significant impact on 24-hour sulfur dioxide increment and visibility in the Dolly Sods Wilderness; the 3-hour and 24-hour sulfur dioxide increment, sulfur deposition, and visibility in the Otter Creek Wilderness; and visibility in Shenandoah National Park. Because of that cumulative analyses are required to evaluate increment consumption in these Class I areas. There are no cumulative analyses and the modeling results are incomplete.

UNITED STATES DISTRICT COURT
MIDDLE DISTRICT OF FLORIDA

UNITED STATES OF AMERICA,)
)
Plaintiff,)
) CIVIL ACTION NO. 99-2524
v.) CIV-T-23F
)
)
TAMPA ELECTRIC COMPANY,)
)
Defendant.)
)

CONSENT DECREE

WHEREAS, Plaintiff, the United States of America (Plaintiff or the United States), on behalf of the United States Environmental Protection Agency (EPA) filed a Complaint on November 3, 1999, alleging that Defendant, Tampa Electric Company (Tampa Electric) commenced construction of major modifications of major emitting facilities in violation of the Prevention of Significant Deterioration (PSD) requirements at Part C of the Clean Air Act (Act), 42 U.S.C. §§ 7470-7492;

WHEREAS, EPA issued a Notice of Violation with respect to such allegations to Tampa Electric on November 3, 1999 (the NOV);

WHEREAS, the parties recognize, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated in good faith and at arm s length; that the parties have voluntarily agreed to this Consent Decree; that implementation of this Consent Decree will avoid prolonged and complicated litigation between the parties; and that this Consent Decree is fair, reasonable, consistent with the goals of the Act, and in the public interest;

WHEREAS, the United States alleges that the Complaint states a claim upon which relief can be granted against Tampa Electric under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and 28 U.S.C. § 1355;

WHEREAS, Tampa Electric has not answered or otherwise responded to the Complaint in light of the settlement memorialized in this Consent Decree;

WHEREAS, Tampa Electric has denied and continues to deny the violations alleged in the NOV and the Complaint; maintains that it has been and remains in compliance with the Clean Air Act and is not liable for civil penalties or injunctive relief; and states that it is agreeing to the obligations imposed by this Consent Decree solely to avoid the costs and uncertainties of litigation and to improve the environment in and around the Tampa Bay area of Florida;

WHEREAS, Tampa Electric is the first electric utility of those against which the United States brought enforcement actions in November, 1999, to come forward and invest time and effort sufficient to develop a settlement with the United States;

WHEREAS, Tampa Electric s decision to Re-Power some of its coal-fired electric generating Units with natural gas will significantly reduce emissions of both regulated and unregulated pollutants below levels that would have been achieved merely by installing appropriate pollution control technologies on Tampa Electric s existing coal-fired electric generating Units;

WHEREAS, prior to the filing of the Complaint or issuance of the Notice of Violation in this matter, Tampa Electric already had placed in service or installed both scrubbers and electrostatic precipitators that serve all existing coal-fired electric generating Units at the company s Big Bend electric generating plant;

WHEREAS, the United States recognizes that a BACT Analysis conducted under existing procedures most likely would not find it cost effective to replace Tampa Electric s existing control equipment at Big Bend for particulate matter, in light of the design and performance of that equipment;

WHEREAS, Tampa Electric and the United States have crafted this Consent Decree to take into account physical and operational constraints resulting from the unique, Riley Stoker wet bottom, turbo-fired boiler technology now in operation at Big Bend, which could limit the efficiency of nitrogen oxides emissions controls installed for those boilers;

WHEREAS, Tampa Electric regularly combusts coal with a sulphur content of five or six pounds per mmBTU heat input;

WHEREAS, Tampa Electric is a mid-sized electric utility and is smaller on a financial basis than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, Tampa Electric owns and operates fewer coal-fired electric generating plants than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, the two Tampa Electric plants addressed by this enforcement action constitute over ninety percent of the entire base load generating capacity of Tampa Electric;

WHEREAS, the United States and Tampa Electric have agreed that settlement of this action is in the best interest of the parties and in the public interest, and that entry of this Consent

Decree without further litigation is the most appropriate means of resolving this matter; and

WHEREAS, the United States and Tampa Electric have consented to entry of this Consent Decree without trial of any issue;

NOW, THEREFORE, without any admission of fact or law, and without any admission of the violations alleged in the Complaint or NOV, it is hereby ORDERED AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter herein and over the parties consenting hereto pursuant to 28 U.S.C. § 1345 and pursuant to Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477. Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the underlying Complaint, Tampa Electric waives all objections and defenses that it may have to the claims set forth in the Complaint, the jurisdiction of the Court or to venue in this District. Tampa Electric shall not challenge the terms of this Consent Decree or this Court s jurisdiction to enter and enforce this Consent Decree. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than the United States and Tampa Electric. Tampa Electric consents to entry of this Consent Decree without further notice.

II. APPLICABILITY

2. The provisions of this Consent Decree shall apply to and be binding upon the United

States and upon Tampa Electric, its successors and assigns, and Tampa Electric s officers, employees and agents solely in their capacities as such. If Tampa Electric proposes to sell or transfer any of its real property or operations subject to this Consent Decree, it shall advise the purchaser or transferee in writing of the existence of this Consent Decree, and shall send a copy of such written notification by certified mail, return receipt requested, to EPA sixty (60) days before such sale or transfer. Tampa Electric shall not be relieved of its responsibility to comply with all requirements of this Consent Decree unless the purchaser or transferee assumes responsibility for full performance of Tampa Electric s responsibilities under this Consent Decree, including liabilities for nonperformance. Tampa Electric shall not purchase or otherwise acquire capacity and/or energy from a third party in lieu of obtaining it from Gannon or Big Bend unless the seller or provider agrees that the facilities providing such capacity and/or energy will meet the emission control requirements set forth in this Consent Decree or equivalent requirements approved in advance by the United States.

3. Tampa Electric shall provide a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization performing any of the work described in Sections IV or VII of this Consent Decree. Notwithstanding any retention of contractors, subcontractors or agents to perform any work required under this Consent Decree, Tampa Electric shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, Tampa Electric shall not assert as a defense the failure of its employees, servants, agents, or contractors to take actions

necessary to comply with this Consent Decree, unless Tampa Electric establishes that such failure resulted from a Force Majeure event as defined in this Consent Decree.

III. DEFINITIONS

4. Alternative Coal shall mean coal with a sulphur content of no more than 2.2 lb/mmBTU, on an as determined basis.

5. BACT Analysis shall mean the technical study, analysis, review, and selection of recommendations typically performed in connection with an application for a PSD permit. Except as otherwise provided in this Consent Decree, such study, analysis, review, and selection of recommendations shall be carried out in conformance with applicable federal and state regulations and guidance describing the process and analysis for determining Best Available Control Technology (BACT).

6. Big Bend shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric and located in Hillsborough County, Florida, which presently includes four steam generating boilers and associated and ancillary systems and equipment, known as Big Bend Units 1, 2, 3, and 4.

7. Consent Decree shall mean this Consent Decree and the Appendix thereto.

8. Emission Rate shall mean the average number of pounds of pollutant emitted per million BTU of heat input (lb/mmBTU) or the average concentration of a pollutant in parts per million by volume (ppm), as dictated by the unit of measure specified for the rate in question, where:

A. in the case of a coal-fired, steam electric generating unit, such rates shall be calculated as a 30 day rolling average. A 30 day rolling average for an Emission Rate expressed as lb/mmBTU shall be determined by calculating the emission rate for a given operating day, and then arithmetically averaging the emission rates for the previous 29 operating days with that date. A new 30 day rolling average shall be calculated for each new operating day;

B. in the case of a gas-fired, electric generating unit, such rates shall be calculated as a 24-hour rolling average, excluding periods of start up, shutdown, and malfunction as provided by applicable Florida regulations at the time the Emission Rate is calculated. A rolling average for Emission Rates expressed as ppm shall be determined on a given day by summing hourly emission rates for the immediately preceding 24-hour period and dividing by 24;

C. the reference methods for determining Emission Rates for SO_2 and NO_x shall be those specified in 40 C.F.R. Part 75, Appendix F. The reference methods for determining Emission Rates for PM shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5, Method 5B, or Method 17; and

D. nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by methods other than the reference methods specified herein.

9. EPA shall mean the United States Environmental Protection Agency.

10. Gannon shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric, located in Hillsborough County, Florida, which presently includes six steam generating boilers and associated and ancillary systems and

equipment, known as Gannon Units 1, 2, 3, 4, 5, and 6. Tampa Electric intends to rename Gannon Bayside Power Station upon completion of the Re-Powering required under this Consent Decree.

11. lb/mmBTU shall mean pounds per million British Thermal Units of heat input.

12. NOx shall mean oxides of nitrogen.

13. NOV shall mean the Notice of Violation issued by EPA to Tampa Electric dated November 3, 1999.

14. PM shall mean total particulate matter, and the reference method for measuring PM shall be that specified in the definition of Emission Rate in this Consent Decree.

15. ppm shall mean parts per million by dry volume, corrected to 15% O_2.

16. Project Dollars shall mean Tampa Electric s expenditures and payments incurred or made in carrying out the dollar-limited projects identified in Paragraph 35 of Section IV of this Consent Decree (Early Reductions of NO_x from Big Bend Units 1 through 3) and in Section VII of this Consent Decree (NO_x Reduction Projects and Mitigation Projects), to the extent that such expenditures or payments both: (A) comply with the Project Dollar and other requirements set by this Consent Decree for such expenditures and payments in Section VII and in Paragraph 35 of Section IV of this Consent Decree, and (B) constitute either Tampa Electric s properly documented external costs for contractors, vendors, as well as equipment, or its internal costs consisting of employee time, travel, and other out-of-pocket expenses specifically attributable to these particular projects.

17. PSD shall mean Prevention of Significant Deterioration within the meaning of Part C of the Clean Air Act, 42 U.S.C. §§ 7470, et seq.

18. Re-Power shall mean the removal or permanent disabling of devices, systems, equipment, and ancillary or supporting systems at a Gannon or Big Bend Unit such that the Unit cannot be fired with coal, and the installation of all devices, systems, equipment, and ancillary or supporting systems needed to fire such Unit with natural gas under the limits set in this Consent Decree (or with No. 2 fuel oil, as a back up fuel only, and under the limits specified by this Consent Decree) plus installation of the control technology and compliance with the Emission Rates called for under this Consent Decree.

19. Reserve / Standby shall mean those devices, systems, equipment, and ancillary or supporting systems that: (1) are not used as part of the Units that must be Re-Powered under Paragraph 26, (2) are not in operation subsequent to the Re-Powering required under Paragraph 26, (3) are maintained and held by Tampa Electric for system reliability purposes, and (4) may be restarted only by Re-Powering.

20. SCR shall mean Selective Catalytic Reduction.

21. Shutdown shall mean the permanent disabling of a coal-fired boiler such that it cannot burn any fuel nor produce any steam for electricity production, other than through Re-Powering.

22. SO_2" shall mean sulphur dioxide.

23. Title V Permit shall mean the permit required under Subchapter V of the Clean Air Act, 42 U.S.C. § 7661, et seq.

24. Total Baseline Emissions shall mean calendar year 1998 emissions of NO_x, SO_2, and PM comprised of the following amounts for each pollutant:

A. <u>for Gannon</u>: 30,763 tons of $NO_{x,}$ 64,620 tons of SO_2, and 1,914 tons of PM; and

B. <u>for Big Bend</u>: 36,077 tons of NO_x , 107,334 tons of SO_2, and 3,002 tons of PM.

25. Unit shall mean for the purpose of this Consent Decree a generator, the steam turbine that drives the generator, the boiler that produces the steam for the steam turbine, the equipment necessary to operate the generator, turbine and boiler, and all ancillary equipment, including pollution control equipment or systems necessary for the production of electricity. An electric generating plant may be comprised of one or more Units.

IV. EMISSIONS REDUCTIONS AND CONTROLS GANNON AND BIG BEND

A. GANNON

26. <u>Consent Decree-Required Re-Powering of Gannon</u>. Tampa Electric shall Re-Power Units at Gannon with a coal-fired generating capacity of no less than 550 MW (Megawatt), as follows.

A. On or before May 1, 2003, Tampa Electric shall Re-Power Units with a coal-fired generating capacity of no less than 200 MW. On or before December 31, 2004, Tampa Electric shall Re-Power additional Units with a coal-fired generating capacity equal to or greater than the difference between 550 MW of coal-fired generating capacity and the MW value of coal-fired generating capacity that Tampa Electric Re-Powered in complying with the first sentence of this

Subparagraph A.

B. All Re-Powering required by this Paragraph shall include installation and operation of SCR, other pollution control technology approved in advance and in writing by EPA, or any innovative technology demonstration project approved pursuant to Paragraph, 52.C to control Unit emissions. Each Re-Powered Unit shall, in conformance with the definition of Re-Power, use natural gas as its primary fuel and shall meet an Emission Rate for NO_x of no greater than 3.5 ppm.

C. A Unit Re-Powered under this or any other provision of this Consent Decree may be fired with No. 2 fuel oil if and only if: (1) the Unit cannot be fired with natural gas; (2) the Unit has not yet been fired with No. 2 fuel oil as a back up fuel for more than 875 full load equivalent hours in the calendar year in which Tampa Electric wishes to fire the Unit with such oil; (3) the oil to be used in firing the Unit has a sulphur content of less than 0.05 percent (by weight); (4) Tampa Electric uses all emission control equipment for that Unit when it is fired with such oil to the maximum extent possible; and (5) Tampa Electric complies with all applicable permit conditions, including emission rates for firing with No. 2 fuel oil, as set forth in applicable preconstruction and operating permits.

D. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing such Re-Powering. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA-approved control technology and a NO_x Emission Rate no greater than 3.5 ppm.

27. Schedule for Shutdown of Units. Tampa Electric shall Shutdown and cease any and all operation of all six (6) Gannon coal-fired boilers with a combined coal-fired capacity of not less than 1194 MW on or before December 31, 2004. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on Reserve / Standby, unless such Unit is to be, or has been, Re-Powered under Paragraph 26, above. If Tampa Electric later decides to restart any Shutdown Unit retained on Reserve / Standby, then prior to such re-start, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit to meet the NO_x Emission Rate established in the PSD Permit or an Emission Rate for NO_x of 3.5 ppm, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). For any Unit Shutdown and placed on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any such Unit, complies with all requirements issued in such a permit, and complies with all other requirements of this Consent Decree applicable to Re-Powering.

28. Permanent Bar on Combustion of Coal. Commencing on January 1, 2005, Tampa

Electric shall not combust coal in the operation of any Unit at Gannon.

B. BIG BEND

29. Initial Reduction and Control of SO_2 Emissions from Big Bend Units 1 and 2. Commencing upon the later of the date of entry of this Consent Decree or September 1, 2000, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of SO_2 from Big Bend Units 1 and 2 at all times that either Unit 1 or 2 is in operation. Tampa Electric shall operate the scrubber so that at least 95% of all the SO_2 contained in the flue gas entering the scrubber is removed. Notwithstanding the requirement to operate the scrubber at all times Unit 1 or 2 is operating, the following operating conditions shall apply:

A. Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric:

(1) in calendar year 2000, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than sixty (60) calendar days, or any part thereof (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of the sixty (60) day limit), and in calendar years 2001 - 2009, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than forty-five (45) calendar days, or any part thereof, in any calendar year (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of the forty-five (45) day limit) ; or

(2) must operate Unit 1 and/or 2 in any calendar year from 2000 through 2009 either to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 1 and/or 2 to meet such emergency.

B. Whenever Tampa Electric operates Units 1 and/or 2 without all emissions from such Unit(s) being treated by the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at the Unit(s) operating during the outage (except for coal already bunkered in the hopper(s) for Units 1 or 2 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Units1 and/or 2; and (3) continue to control SO_2 emissions from Big Bend Units 1 and/or 2 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3).

C. In calendar years 2010 through 2012, Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric complies with the requirements of Subparagraphs A and B, above, and uses only coal with a sulphur content of 1.2 lb/mmBTU, or less, in place of

Alternative Coal.

D. If Tampa Electric Re-Powers Big Bend Unit 1 or 2, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon such compliance the provisions of Subparagraphs 29.A, 29.B, and 29.C shall not apply to the affected Unit.

30. Initial Reduction and Control of SO_2 Emissions from Big Bend Unit 3. Commencing upon entry of the Consent Decree, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of SO_2 from Big Bend Units 3 and 4 at all times that Unit 3 is in operation. When Big Bend Units 3 and 4 are both operating, Tampa Electric shall operate the scrubber so that at least 93% of all the SO_2 contained in the flue gas entering the scrubber is removed. When Big Bend Unit 3 alone is operating, until May 1, 2002, Tampa Electric shall operate the scrubber so that at least 93% of all SO_2 contained in the flue gas entering the scrubber is removed or the Emission Rate for SO_2 for Unit 3 does not exceed 0.35 lb/mmBTU. When Unit 3 alone is operating, from May 1, 2002 until January 1, 2010, Tampa Electric shall operate the scrubber so that at least 95% of the SO_2 contained in the flue gas entering the scrubber is removed or the Emission Rate for SO_2 does not exceed 0.30 lb/mmBTU. Notwithstanding the requirement to operate the scrubber at all times Unit 3 is operating, and providing Tampa Electric is otherwise in compliance with this Consent Decree, the following operating conditions shall apply:

A. In any calendar year from 2000 through 2009, Tampa Electric may operate Unit 3 in the case of outages of the scrubber serving Unit 3, but only so long as Tampa

Electric:

(1) does not operate Unit 3 during outages on more than thirty (30) calendar days, or any part thereof, in any calendar year; or

(2) must operate Unit 3 either: to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 3 to meet such emergency.

B. Whenever Tampa Electric operates Unit 3 without treating all emissions from that Unit with the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at Unit 3 during the outage (except for coal already bunkered in the hopper(s) for Unit 3 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Unit 3; and (3) continue to control SO_2 emissions from Big Bend Unit 3 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units, 1, 2, and 3).

C. If Tampa Electric Re-Powers Big Bend Unit 3, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon compliance with Paragraph 40 the provisions of Subparagraphs 30.A and 30.B shall not apply to Unit 3.

D. Nothing in this Consent Decree shall alter requirements of the New Source Performance Standards (NSPS), 40 C.F.R. Part 60 Subpart Da, that apply to operation of the scrubber serving Unit 4.

31. Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3. Tampa Electric shall maximize the availability of the scrubbers to treat the emissions of Big Bend Units 1, 2, and 3, as follows:

A. As soon as possible after entry of this Consent Decree, Tampa Electric shall submit to EPA for review and approval a plan addressing all operation and maintenance changes to be made that would maximize the availability of the existing scrubbers treating emissions of SO_2 from Big Bend Units 1 and 2, and from Unit 3. In order to improve operations and maintenance practices as soon as possible, Tampa Electric may submit the plan in two phases.

(1) Each phase of the plan proposed by Tampa Electric shall include a schedule pursuant to which Tampa Electric will implement measures relating to operation and maintenance of the scrubbers called for by that phase of the plan, within sixty days of its approval by EPA. Tampa Electric shall implement each phase of the plan as approved by EPA. Such plan may be modified from time to time with prior written approval of EPA.

(2) The proposed plan shall include operation and maintenance activities that will minimize instances during which SO_2 emissions are not scrubbed, including but not limited to improvements in the flexibility of scheduling maintenance on the

scrubbers, increases in the stock of spare parts kept on hand to repair the scrubbers, a commitment to use of overtime labor to perform work necessary to minimize periods when the scrubbers are not functioning, and use of all existing capacity at Big Bend and Gannon Units that are served by available, operational pollution control equipment to minimize pollutant emissions while meeting power needs.

(3) If Tampa Electric elects to submit the plan to EPA in two phases, the first phase to be submitted shall address, at a minimum, use of overtime hours to accomplish repairs and maintenance of the scrubber and increasing the stock of scrubber spare parts that Tampa Electric shall keep at Big Bend to speed future maintenance and repairs. If Tampa Electric elects to submit the plan in two phases, EPA shall complete review of the first phase within fifteen business days of receipt. For the second phase of the plan or submission of the plan in its entirety, EPA shall complete review of such plan or phase thereof within 60 days of receipt. Within sixty days after EPA s approval of the plan or any phase of the plan, Tampa Electric shall complete implementation of that plan or phase and continue operation under it subject only to the terms of this Consent Decree.

32. PM Emission Minimization and Monitoring at Big Bend.

A. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete an optimization study which shall recommend the best operational practices to minimize emissions from each Electrostatic Precipitator (ESP) and shall deliver the completed study to EPA for review and approval. Tampa

Electric shall implement these recommendations within sixty days after EPA has approved them and shall operate each ESP in conformance with the study and its recommendations until otherwise specified under this Consent Decree.

B. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete a BACT Analysis for upgrading each existing ESP now located at Big Bend and shall deliver the Analysis to EPA for review and approval. Notwithstanding the definition of BACT Analysis in this Consent Decree, Tampa Electric need not consider in this BACT Analysis the replacement of any existing ESP with a new ESP, scrubber, or baghouse, or the installation of a supplemental pollution control device of similar cost to a replacement ESP, scrubber, or baghouse. Tampa Electric shall simultaneously deliver to EPA all documents that support the BACT Analysis or that were considered in preparing the Analysis. Tampa Electric shall retain a qualified contractor to assist in the performance and completion of the BACT Analysis. On or before May 1, 2004, after EPA approval of the recommendation(s) made by the BACT Analysis, Tampa Electric shall complete installation of all equipment called for in the recommendation(s) of the Analysis and thereafter shall operate each ESP in conformance with the recommendation(s), including compliance with the Emission Rate(s) specified by the recommendation(s).

C. Within six months after Tampa Electric completes installation of the equipment called for by the BACT Analysis, as approved by EPA, Tampa Electric shall revise the previous optimization study and shall recommend the best operational practices to minimize emissions from each ESP, taking into account the recommendations from the BACT Analysis required by this Paragraph, and shall deliver the completed study to EPA for review and approval. Commencing no later than 180 days after EPA approves the study and its recommendation(s), Tampa Electric shall operate each ESP in conformance with the study s recommendation.

D. Tampa Electric shall include the recommended operational practices for each ESP and the recommendations from the BACT Analysis in Tampa Electric s Title V Permit application and all other relevant applications for operating or construction permits.

E. Installation and Operation of a PM Monitor. On or before March 1, 2002, Defendant shall install, calibrate, and commence continuous operation of a continuous particulate matter emissions monitor (PM CEM) in the duct at Big Bend that services Unit 4. Data from the PM CEM shall be used by Tampa Electric, at a minimum, to monitor progress in reducing PM emissions.

F. Continuous operation of the PM CEM shall mean operation at all times that Unit 4 operates, except for periods of malfunction of the PM CEM or routine maintenance performed on the PM CEM. If after Tampa Electric operates this PM CEM for at least two years, and if the parties then agree that it is infeasible to sustain continuous operation of the PM CEM, Tampa Electric shall submit an alternative PM monitoring plan for review and approval by EPA. The plan shall include an explanation of the basis for stopping operation of the PM CEM and a proposal for an alternative monitoring protocol. Until EPA approves such plan, Tampa Electric shall continue to operate the PM CEM.

G. Installation and Operation of Second PM Monitor. If Tampa Electric advises EPA, pursuant to Paragraph 36, that it has elected to continue to combust coal at Big Bend Units 1, 2, or 3, and Tampa Electric has not ceased operating the first PM CEM as described in Subparagraph F, above, then Tampa Electric shall install, calibrate, and commence continuous operation of a PM CEM on a second duct at Big Bend on or before May 1, 2007. The requirement to operate a PM CEM under any provision of this Paragraph shall terminate if and when the Unit monitored by the PM CEM is Re-Powered.

H. Testing and Reporting Requirement. Prior to installation of the PM CEM on each duct, Tampa Electric shall conduct a stack test on each stack at Big Bend on at least an annual basis and report its results to EPA as part of the quarterly report under Section V. The stack test requirement in this Subparagraph may be satisfied by Tampa Electric s annual stack tests conducted as required by its permit from the State of Florida. Following installation of each PM CEM, Defendant shall include in its quarterly reports to EPA pursuant to Section V all data recorded by the PM CEM, in electronic format, if available.

I. Nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by the PM CEMs.

33. Election for Big Bend Unit 4: Shutdown, Re-Power, or Continued Combustion of Coal.

Tampa Electric shall advise EPA in writing, on or before May 1, 2005, whether Big Bend Unit 4 will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

34. Reduction of NO_x at Big Bend Unit 4 after 2005 Election. Based on Tampa Electric s election in Paragraph 33, Tampa Electric shall take one of the following actions:

A. If Tampa Electric elects to continue firing Unit 4 with coal, on or before June 1, 2007, Tampa Electric shall install and commence operation of SCR, or other technology if approved in writing by EPA in advance, sufficient to limit the coal-fired Emission Rate of NO_x from Unit 4 to no more than 0.10 lb/mmBTU. Thereafter, Tampa Electric shall continue operation of SCR or other EPA approved control technology, and Tampa Electric shall continue to meet an Emission Rate for NO_x from Unit 4 no greater than 0.10 lb/mmBTU; or

B. If Tampa Electric elects to Re-Power Unit 4, Tampa Electric shall not combust coal at Unit 4 on or after June 1, 2007. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of the Re-Powering of Unit 4. In applying for such permit, Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a NO_x Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent; or

C. If Tampa Electric elects to Shutdown Big Bend Unit 4, Tampa Electric shall complete Shutdown of Big Bend Unit 4 on or before June 1, 2007.

Notwithstanding the requirements of this Subparagraph, Tampa Electric may retain this Unit, after it is Shutdown pursuant to this Subparagraph, on Reserve / Standby. If Tampa Electric later decides to restart Unit 4 then, prior to such restart, Tampa Electric shall timely apply for a PSD permit, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Subparagraph, Tampa Electric may never again use coal to fire that Unit.

D. Notwithstanding the provisions of Subparagraphs B and C above or the definition of Re-Power in this Consent Decree, Tampa Electric may also elect to fuel Big Bend Unit 4 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in this Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

35. Early Reductions of NO_x from Big Bend Units 1 through 3: On or before December 31, 2001, Tampa Electric shall submit to EPA for review and comment a plan to reduce NO_x emissions from Big Bend Units 1, 2 and 3, through the expenditure of up to $3 million

Project Dollars on combustion optimization using commercially available methods, techniques, systems, or equipment, or combinations thereof. Subject only to the financial limit stated in the previous sentence, for Units 1 and 2 the goal of the combustion optimization shall be to reduce the NO_x Emission Rate by at least 30% when compared against the NO_x Emissions Rate for these Units during calendar year 1998, which the United States and Tampa Electric agree was 0.86 lb/mmBTU. For Unit 3 the goal of the combustion optimization shall be to reduce the NO_x Emissions Rate by at least 15% when compared against the NO_x Emission Rate for this Unit during calendar year 1998, which the United States and Tampa Electric agree was 0.57 lb/mmBTU. If the financial limit in this Paragraph precludes designing and installing combustion controls that will meet the percentage reduction goals for the NO_x Emission Rates specified in this Paragraph for all three Units, then Tampa Electric s plan shall first maximize the Emission Rate reductions at Units 1 and 2 and then at Unit 3. Unless the United States has sought dispute resolution on Tampa Electric s plan on or before May 30, 2002, Tampa Electric shall implement all aspects of its plan at Big Bend Units 1, 2, and 3 on or before December 31, 2002. On or before April 1, 2003, Tampa Electric shall submit to EPA a report that documents the date(s) of complete implementation of the plan, the results obtained from implementing the plan, including the emission reductions or benefits achieved, and the Project Dollars expended by Tampa Electric in implementing the plan.

36. <u>Election for Big Bend Units 1 through 3: Shutdown, Re-Power, or Continued Combustion of Coal</u>. Tampa Electric shall advise EPA in writing, on or before May 1,

2007, whether Big Bend Units 1, 2, or 3, or any combination of them, will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

37. Further NO_x Reduction Requirements if Big Bend Units 1, 2, and/or 3 Remain Coal-fired. If Tampa Electric advises EPA in writing, pursuant to Paragraph 36, above, that Tampa Electric will continue to combust coal at Units 1, 2, and/or 3, then:

A. Subject only to Subparagraphs B and D, Tampa Electric shall timely solicit contract proposals to acquire, install, and operate SCR, or other technology if approved in writing by EPA in advance, sufficient to limit the Emission Rate of NO_x to no more than 0.10 lb/mmBTU at each Unit that will combust coal. Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve an Emission Rate of NO_x on each such Unit no less stringent than 0.10 lb/mmBTU.

B. Notwithstanding Subparagraph A, Tampa Electric shall not be required to install SCR to limit the Emission Rate of NO_x at Units 1, 2 and/or 3 to 0.10 lb/mmBTU if the installation cost ceiling contained in this Paragraph will be exceeded by such installation. If Tampa Electric decides to continue burning coal at Units 1, 2 and 3, the installation cost ceiling for SCR at Units 1, 2, and 3 shall be three times the cost of installing SCR at Big Bend Unit 4 plus forty-five (45%) percent of the cost of installing SCR at Big Bend 4. If Tampa Electric decides to continue burning coal at only two Units at Big Bend, the installation cost ceiling for SCR at those two Units shall be two times the cost of installing SCR at Big Bend 4 plus forty-five (45) percent of the cost of installing SCR at Big Bend Unit 4. If

Tampa Electric decides to continue burning coal at only one Unit at Big Bend, the installation cost ceiling for SCR at that Unit shall be the cost of installing SCR at Big Bend 4 plus forty five (45) percent.

C. If, based on the contract proposals obtained under Subparagraph A, Tampa Electric determines that the projected cost of proposed control equipment satisfying a 0.10 lb/mmBTU Emission Rate will not exceed the installation cost ceiling, Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve a NO_x Emission Rate on each Unit no less stringent than 0.10 lb/mmBTU. If, based on the contract proposals, Tampa Electric determines that the projected cost will exceed the installation cost ceiling, Tampa Electric shall so advise EPA and shall provide EPA with the basis for Tampa Electric s determination, including all documentation sufficient to replicate and evaluate Tampa Electric s cost projections.

D. Unless EPA contests Tampa Electric s determination that the installation cost ceiling will be exceeded by installing control equipment to reduce NO_x emissions to 0.10 lb/mmBTU or less, Tampa Electric shall install, at each Unit that will continue to combust coal, the NO_x control technology designed to achieve the lowest Emission Rate that can be attained within the installation cost ceiling. Notwithstanding any provision of this Consent Decree, including the installation cost ceiling, Tampa Electric shall install NO_x control technology that is designed to achieve an Emission Rate no less stringent than 0.15 lb/mmBTU. Each Unit combusting coal and its NO_x controls shall meet the Emission Rate for which they are designed.

E. Tampa Electric shall acquire, install, commence operating emission control equipment, and meet the applicable Emission Rate for NO_x at each of the Units to remain coal-fired, as follows: (1) for the first of the Units to remain coal-fired, or if only one Unit is to be coal-fired, on or before May 1, 2008; (2) for the second Unit, if there is one, on or before May 1, 2009; (3) for the third Unit, if there is one, on or before May 1, 2010.

38. Tampa Electric s NO_x Reduction Requirements if Tampa Electric Re-Powers Units 1, 2, and/or 3 . If, by May 1, 2007, Tampa Electric advises EPA that Tampa Electric has elected to Re-Power one or more of Units 1, 2, and 3 at Big Bend, then Tampa Electric shall complete all steps necessary to accomplish such Re-Powering in a time frame to commence operation of the Re-Powered Unit(s) no later than May 1, 2010. Any Unit(s) to be replaced by a Re-Powered Unit may continue to operate until the earlier of six months after the date the Re-Powered Unit begins commercial operation or December 31, 2010. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of any Re-Powered Unit at Big Bend. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a NO_x Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate any Unit Re-Powered under this Paragraph to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent. Notwithstanding the provisions of this Paragraph or the definition of Re-Power in this

Consent Decree, Tampa Electric may also elect to fuel Units 1, 2, or 3 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in any of these Units, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

39. Requirements Applicable to Big Bend Units 1, 2, and/or 3 if Shutdown. If Tampa Electric elects to Shutdown one or more of Units1, 2, and 3, Tampa Electric shall complete Shutdown of the first such Unit on or before May 1, 2008; of the second Unit, if applicable, on or before May 1, 2009, and of the third Unit, if applicable, on or before May 1, 2010. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on Reserve / Standby. If Tampa Electric later decides to restart such Unit retained on Reserve / Standby by Re-Powering it then, prior to such restart, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as result of that application, including installation of BACT and its corresponding Emission Rate determined at the time of the restart. Tampa Electric shall operate each Unit Re-Powered under this Paragraph to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Paragraph, Tampa Electric may never again use coal to fire that Unit.

For any Unit Shutdown and placed on on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any of such Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

40. Further SO_2 Reduction Requirements if Big Bend Units 1, 2, or 3 Remains Coal-fired. If Tampa Electric elects under Paragraph 36 to continue combusting coal at Units 1, 2, and/or 3, Tampa Electric shall meet the following requirements.

A. Removal Efficiency or Emission Rate. Commencing on dates set forth in Subparagraph C and continuing thereafter, Tampa Electric shall operate coal-fired Units and the scrubbers that serve those Units so that emissions from the Units shall meet at least one of the following limits:

(1) the scrubber shall remove at least 95% of the SO_2 in the flue gas that entered the scrubber; or

(2) the Emission Rate for SO_2 from each Unit does not exceed 0.25 lb/mmBTU.

B. Availability Criteria. Commencing on the deadlines set in this Paragraph and continuing thereafter, Tampa Electric shall not allow emissions of SO_2 from Big Bend Units 1, 2, or 3 without scrubbing the flue gas from those Units and using other equipment designed to control SO_2 emissions. Notwithstanding the preceding sentence, to the extent that the Clean Air Act New Source Performance Standards identify circumstances during which Bend Unit 4 may operate without its scrubber, this Consent Decree shall allow Big Bend Units1, 2, and/or 3 to operate when those same circumstances are present at Big Bend Units 1, 2, and/or 3.

C. Deadlines. Big Bend Unit 3 and the scrubber(s) serving it shall be subject to the requirements of this Paragraph beginning January 1, 2010 and continuing thereafter. Until January 1, 2010, Tampa Electric shall control $S0_2$ emissions from Unit 3 as required by Paragraphs 30 and 31. Big Bend Units 1 and 2 and the scrubber(s) serving them shall be subject to the requirements of this Paragraph beginning January 1, 2013 and continuing thereafter. Until January 1, 2013, Tampa Electric shall control $S0_2$ emissions from Units 1 and 2 as required by Paragraphs 29 and 31.

D. Nothing in this Consent Decree shall alter requirements of NSPS, 40 C.F.R. Part 60 Subpart Da, that apply to operation of Unit 4 and the scrubber serving it.

C. BIG BEND AND GANNON -- PERMITS AND RESOLUTION OF CLAIMS

41. Timely Application for Permits. Except as otherwise stated in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires Tampa Electric to secure a permit to authorize constructing or operating any device under this Consent Decree, Tampa Electric shall make such application in a timely manner. Such applications shall be completed and submitted to the appropriate authorities to allow sufficient time for all legally required processing and review of the permit request. Failure to comply with this provision shall bar any use by Tampa Electric of the Force

Majeure provisions of this Consent Decree.

42. Title V Permits.

A. On or before January 1, 2004, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Gannon, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

B. On or before January 1, 2009, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Big Bend, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

C. Except as this Consent Decree expressly requires otherwise, this Consent Decree shall not be construed to require Tampa Electric to apply for or obtain a permit pursuant to the Prevention of Significant Deterioration requirements of the Clean Air Act for any work performed by Tampa Electric within the scope of the Resolution of Claims provisions of Paragraphs 43 and 44, below.

43. Resolution of Past Claims - This Consent Decree resolves all of Plaintiff s civil claims

for liability arising from violations of either: (1) the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401, et seq at Units at Big Bend or Gannon, or (2) 40 C.F.R. Section 60.14 at Units at Big Bend or Gannon, that :

A. are alleged in the Complaint filed November 3, 1999, or in the NOV issued on that date;

B. could have been alleged by the United States in the Complaint filed November 3, 1999, or in the NOV issued on that date; or

C. have arisen from Tampa Electric s actions that occurred between November 3, 1999 and the date on which this Consent Decree is entered by the Court.

44. Resolution of Future Claims - Covenant not to Sue . The United States covenants not to sue Tampa Electric for civil claims arising from the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401 et seq., at Big Bend or Gannon Units and that are based on failure to obtain PSD or nonattainment New Source Review (NSR) permits for:

A. work that this Consent Decree expressly directs Tampa Electric to undertake; or

B. physical changes or changes in the method of operation of Big Bend or Gannon Units not required by this Consent Decree, if and only if:

    (1) such change is commenced after Tampa Electric is implementing the plan, or the first phase of the plan if applicable, approved by EPA under Paragraph 31 (Optimizing Availability of Scrubbers),

    (2) such change is commenced, within the meaning of 40 C.F.R. Section

52.21(b)(9), during the time this Consent Decree applies to the Unit at which this change has been made ;

(3) Tampa Electric is otherwise in compliance with this Consent Decree;

(4) hourly Emission Rates of NO_x, SO_2, or PM at the changed Unit(s) do not exceed their respective hourly Emission Rates prior to the change, as measured by 40 C.F.R. § 60.14(h); and

(5) in any calendar year following the change, emissions of no pollutant within the scope of Total Baseline Emissions exceed the emissions of that pollutant in the Total Baseline Emissions.

45. Separate Limitation on Resolution of Claims. Notwithstanding the provisions of Section XIII (Termination), the provisions of Paragraph 44 (Resolution of Future Claims - Covenant Not to Sue) shall terminate at Gannon and Big Bend, as follows. On December 31, 2006, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Gannon. On December 31, 2012, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Big Bend. If Tampa Electric Re-Powers any Unit at Big Bend under the terms provided by this Consent Decree, then for each such Unit the provisions of Paragraph 44 shall terminate two years after each such Unit is Re-Powered or on December 31, 2012, whichever is earlier.

46. Exclusion of Certain Emission Allowances. For any and all actions taken by Tampa Electric pursuant to the terms of this Consent Decree, including but not limited to

upgrading of ESPs and scrubbers, installation of NO_x controls, Re-Powering, and Shutdown, Tampa Electric shall not use or sell any resulting NO_x or SO_2 emission allowances or credits in any emission trading or marketing program of any kind; provided, however, that:

A. SO_2 credits allocated to Tampa Electric by the Administrator of EPA under the Act, due to the Re-Powering or Shutdown of Gannon, may be retained by Tampa Electric during the year in which they are allocated, but only for Tampa Electric s own use in meeting any acid rain requirement imposed under the Act. For any such allowances not used by Tampa Electric for this purpose by June 30 of the following calendar year, Tampa Electric shall not use, sell, trade, or otherwise transfer these allowances for its benefit or the benefit of a third party unless such a transfer would result in the retiring of such allowances without their ever being used.

B. If Tampa Electric decides to Re-Power any Unit at Big Bend, then Tampa Electric shall be entitled to retain for any purpose under law the difference between the emission allowances that would have resulted from installing BACT-level NO_x and SO_2 controls at the existing coal-fired Unit and the emission allowances that result from Re-Powering that Unit. Before Tampa Electric uses any allowances within the scope of this Subparagraph, Tampa Electric shall submit the calculation of the net emission allowances for approval by the United States.

C. Nothing in this Consent Decree shall preclude Tampa Electric from using or selling emission allowances arising from Tampa Electric s activities occurring prior to December 31, 1999, or Tampa Electric s activities after that date that are not related to actions required of Tampa Electric under this Consent Decree. The United States and Tampa Electric agree that the operation of the SO_2 scrubber serving Big Bend Units 1 and 2 meets the requirements of this Subparagraph, and that emission allowances resulting from the operation of this scrubber shall not be treated as an activity related to or required under this Consent Decree.

V. REPORTING AND RECORD KEEPING

47. Beginning at the end of the first calendar quarter after entry of this Consent Decree, and in addition to any other express reporting requirement in this Consent Decree, Tampa Electric shall submit to EPA a quarterly report, consistent with the form attached to this Consent Decree as the Appendix, within thirty (30) days after the end of each calendar quarter until this Consent Decree is terminated.

48. Tampa Electric s report shall be signed by Tampa Electric s Vice President, Environmental and Fuels, or, in his or her absence, Vice President, Energy Supply, or higher ranking official, and shall contain the following certification:

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

VI. CIVIL PENALTY

49. Within thirty (30) calendar days of entry of this Consent Decree, Tampa Electric shall pay to the United States a civil penalty in the amount of $3.5 million. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing the USAO File Number and DOJ Case Number 90-5-2-1-06932 and the civil action case name and case number of this action. The costs of such EFT shall be Tampa Electric s responsibility. Payment shall be made in accordance with instructions provided by the Financial Litigation Unit of the U.S. Attorney's Office for the Middle District of Florida. Any funds received after 11:00 a.m. (EST) shall be credited on the next business day. Tampa Electric shall provide notice of payment, referencing the USAO File Number, DOJ Case Number 90-5-2-1- 06932, and the civil action case name and case number, to the Department of Justice and to EPA, as provided in Paragraph 82 (Notice). Failure to timely pay the civil penalty shall subject Tampa Electric to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render Tampa Electric liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

VII. NO$_x$ REDUCTION PROJECTS AND MITIGATION PROJECTS

50. Tampa Electric shall submit plans for and shall implement the NO$_x$ Reduction and Other Mitigation Projects (referred to together as Projects) described in this Section, and in Paragraph 35 of this Consent Decree, in compliance with the schedules and terms of this

Consent Decree. In performing these Projects, Tampa Electric shall spend no less than \$10 million in Project Dollars, in total, unless the Additional NO_x Reduction Project(s) selected under Paragraph 52.C is estimated to cost more than \$5 million, in which case Tampa Electric shall spend no less than \$10 million but no more than \$11 million in Project Dollars, in total. Tampa Electric shall expend the full amount of the Project Dollars required by this Paragraph on or before May 1, 2010. Tampa Electric shall maintain for review by EPA, upon its request, all documents identifying Project Dollars spent by Tampa Electric.

51. All plans and reports prepared by Tampa Electric pursuant to the requirements of Paragraph 35 and this Section of the Consent Decree shall be publicly available without charge.

52. Tampa Electric shall submit the required plans for and complete the following Projects:

A. Early NO_x reductions through combustion optimization as described in Paragraph 35 of this Consent Decree.

B. <u>Performance of Air Chemistry Work in Tampa Bay Estuary</u>. Tampa Electric shall expend no more than \$2 million Project Dollars in conducting or financing stack tests, emissions estimation, ambient air monitoring, data acquisition and analysis, and any combination thereof that: (1) is not otherwise required by law, (2) will provide data or analysis that is not already available, (3) will complement work carried out by other persons examining the air chemistry of Tampa Bay Estuary, and (4) will help close gaps in current understanding of air chemistry in the Tampa Bay Estuary. Tampa Electric shall either conduct this work itself, fund other persons already conducting such work on a non-profit basis, or both. For work Tampa Electric intends to conduct itself, the company shall describe the proposed work and a schedule for completion to EPA, in writing, at least 90 days prior to the date on which Tampa Electric intends to start such work, including an explanation of why the proposed work meets all the requirements of this Subparagraph. Unless EPA objects to the proposed work on the grounds it does not comply with the requirements of this Subparagraph, Tampa Electric shall undertake and complete the work according to the proposed schedule. If Tampa Electric elects to spend some or all of the $2 million Project Dollars to finance work to be performed by other persons or organizations, the company shall provide to EPA for review and approval a plan that describes the work to be performed, the persons or organizations conducting the work, the schedule for its completion, the schedule for Tampa Electric s payments, and an explanation of why the proposed payment(s) meets all the requirements of this Subparagraph. The plan shall be provided to EPA at least 90 days prior to the date on which Tampa Electric will begin transferring the money to finance such work. All payments to persons or organizations under such a plan shall be completed by Tampa Electric no later than June 30, 2002. Before Tampa Electric makes such payments for the benefit of any person or organization carrying out work under this Paragraph, Tampa Electric shall secure a written, signed commitment from such person to provide Tampa Electric and EPA with the results of the work.

C. Additional NO_x Reductions Project(s).

(1) General Requirement. Tampa Electric shall expend the remainder of the Project Dollars required under this Consent Decree to: (i) demonstrate innovative NO_x control technologies on any of its Units or boilers at Gannon or Big Bend not Shutdown or on Reserve / Standby; and/or (ii) reduce the NO_x Emission Rate for any Big Bend coal-combusting Unit below the lowest rate otherwise applicable to it under this Consent Decree.

(2) For any Project(s) at Gannon. If Tampa Electric elects to undertake a project on an eligible Gannon Unit(s) to demonstrate any innovative NO_x control technology, within six months after entry of this Consent Decree Tampa Electric shall submit a plan to EPA, for review and approval, which sets forth: (a) the NO_x demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in NO_x or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for commencement and completion in accordance with the requirements of this Subparagraph. . EPA shall complete its review of this plan within 60 days after receipt. If such project is approved, Tampa Electric shall complete installation of the technology no later than December 31, 2004 as part of the Re-Powering of such Units; provided, however, that nothing in this Paragraph

alters Tampa Electric s obligation under Paragraph 26 of this Consent Decree.

(3) For any Project(s) at Big Bend. At least three (3) years prior to the date on which the expenditure of any Project Dollars is to commence on Big Bend under this Subparagraph C, Tampa Electric shall submit a plan to EPA for review and approval which sets forth: (a) the NO_x demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in NO_x or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for commencement and completion in accordance with the requirements of this Subparagraph. If EPA approves the projects contained in the plan, Tampa Electric shall implement the project(s). Projects that would demonstrate innovative NO_x control technology or reduce the NO_x Emission Rate for any Big Bend coal-fired or Re-Powered Unit shall be operating and achieving reductions or demonstrating the performance of the innovative technology, as applicable, not later than May 1, 2010.

(4) Follow-up Report(s). Within sixty (60) days following the implementation of each EPA-approved project, Tampa Electric shall submit to EPA a report that documents the date that all aspects of the project were implemented, Tampa Electric s results in implementing the project, including the emission reductions or other environmental benefits

achieved, and the Project Dollars expended by Tampa Electric in implementing the project.

VIII. STIPULATED PENALTIES

53. For purposes of this Consent Decree, within thirty days after written demand from the United States, and subject to the provisions of Sections X (Force Majeure) and XI (Dispute Resolution), Tampa Electric shall pay the following stipulated penalties to the United States for each failure by Tampa Electric to comply with the terms of this Consent Decree.

A. For failure to pay timely the civil penalty as specified in Section VI of this Consent Decree, $10,000 per day.

B. For all violations of a 24 hour Emission Rate (1) Less than 5% in excess of limit: $4,000 per day, per violation; (2) more than 5% but less than 10% in excess of limit: $9,000 per day per violation; (3) equal to or greater than 10% in excess of limit: $27,500 per day, per violation

C. For all violations of 30-day rolling average Emission Rates (1) Less than 5% in excess of limit: $150 per day per violation; (2) more than 5% but less than 10% in excess of limit: $300 per day per violation; (3) equal to or greater than 10% in excess of limit: $800 per day per violation. Violation of an Emission Rate that is based on a 30 day rolling average is a violation on every day of the 30 day period on which the average is based . Where a violation of a 30 day rolling monthly average Emission Rate (for the same pollutant and from the same source) recurs within periods less than 30 days, Tampa Electric shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

D. For all violations of a 95% removal efficiency requirement (1) For removal efficiency less than 95% but greater than or equal to 94%, $4,000 per day, per violation; (2) for removal efficiency less than 94% but greater than or equal to 91%, $9,000 per day, per violation; (3) for removal efficiency less than 91%, $27,500 per day, per violation. For all violations of a 93% removal efficiency requirement (1) For removal efficiency less than 93% but greater than or equal to 92%, $4,000 per day, per violation; (2) for removal efficiency less than 92% but greater than or equal to 90%, $9,000 per day, per violation; (3) for removal efficiency less than 90%, $27,500 per day, per violation;

E. Violation of deadlines for Shutdown of boilers or Units or megawatt capacity $27,500 per day, per violation.

F. Failure to apply for the permits required by Paragraphs 26, 27, 34, 38, and 42 $1,000 per day, per violation.

G. Failure to implement the recommendations of the PM BACT Analysis or the PM optimization study by May 1, 2004 $5,000 per day, per violation for first 30 days; $15,000 per day, per violation, for next 30 days; $27,500 per day, per violation, thereafter.

H. Failure to commence combustion optimization at Big Bend Units 1, 2, or 3 on or before May 30, 2003 as required by Paragraph 35, $10,000 per day, per violation.

I. Failure to operate the scrubbers at Big Bend Units 1, 2, or 3 on any day except as permitted by Paragraphs 29, 30, or 31, $27,500 per day, per violation.

J. Failure to submit quarterly progress and monitoring report $100 per day, per violation, for first ten days late, and $500 per day for each day thereafter.

K. Failure to complete timely any action or payment required by or established under Subparagraph 52(B) (Performance of Air Chemistry Work in Tampa Bay Estuary), $5,000 per day, per violation

L. Failure to perform NO_x reduction or demonstration project(s), by the deadline(s) established in Subparagraph 52.C (Additional NO_x Reductions Project(s)), $10,000 per day, per violation;

M. For failure to spend at least the number of Project Dollars required by this Consent Decree by date specified in Paragraph 50, $5,000 per day, per violation;

N. Violation of any Consent Decree prohibition on use of allowances as provided in Paragraph 46 three times the market value of the improperly used allowance as measured at the time of the improper use.

54. Should Tampa Electric dispute its obligation to pay part or all of a stipulated penalty demanded by the United States, it may avoid the imposition of a separate stipulated penalty for the failure to pay the disputed penalty by depositing the disputed amount in a commercial escrow account pending resolution of the matter and by invoking the Dispute Resolution provisions of this Consent Decree within the time provided in this Section VIII of the Consent Decree for payment of the disputed penalty. If the dispute is thereafter resolved in Tampa Electric's favor, the escrowed amount plus accrued interest

shall be returned to Tampa Electric. If the dispute is resolved in favor of the United States, it shall be entitled to the escrowed amount determined to be due by the Court, plus accrued interest. The balance in the escrow account, if any, shall be returned to Tampa Electric.

55. The United States reserves the right to pursue any other remedies to which it is entitled, including, but not limited to, a new civil enforcement action and additional injunctive relief for Tampa Electric's violations of this Consent Decree. If the United States elects to seek civil or contempt penalties after having collected stipulated penalties for the same violation, any further penalty awarded shall be reduced by the amount of the stipulated penalty timely paid or escrowed by Tampa Electric. Tampa Electric shall not be required to remit any stipulated penalty to the United States that is disputed in compliance with Part XI of this Consent Decree until the dispute is resolved in favor of the United States. However, nothing in this Paragraph shall be construed to cease the accrual of the stipulated penalties until the dispute is resolved.

IX. RIGHT OF ENTRY

56. Any authorized representative of EPA or an appropriate state agency, including independent contractors, upon presentation of credentials, shall have a right of entry upon the premises of Tampa Electric's plants identified herein at any reasonable time for the purpose of monitoring compliance with the provisions of this Consent Decree, including inspecting plant equipment and inspecting and copying all records maintained by Tampa Electric required by this Consent Decree. Tampa Electric shall retain such records for a

period of twelve (12) years from the date of entry of this Consent Decree. Nothing in this Consent Decree shall limit the authority of EPA to conduct tests and inspections at Tampa Electric s facilities under Section 114 of the Act, 42 U.S.C. § 7414.

X. FORCE MAJEURE

57. If any event occurs which causes or may cause a delay in complying with any provision of this Consent Decree, Tampa Electric shall notify the United States in writing as soon as practicable, but in no event later than seven (7) business days following the date Tampa Electric first knew, or within ten (10) business days following the date Tampa Electric should have known by the exercise of due diligence, that the event caused or may cause such delay. In this notice Tampa Electric shall reference this Paragraph of this Consent Decree and describe the anticipated length of time the delay may persist, the cause or causes of the delay, the measures taken or to be taken by Tampa Electric to prevent or minimize the delay, and the schedule by which those measures will be implemented. Tampa Electric shall adopt all reasonable measures to avoid or minimize such delays.

58. Failure by Tampa Electric to comply with the notice requirements of Paragraph 57 shall render this Section X voidable by the United States as to the specific event for which Tampa Electric has failed to comply with such notice requirement. If voided, the provisions of this Section shall have no effect as to the particular event involved.

59. The United States shall notify Tampa Electric in writing regarding Tampa Electric's claim of a delay in performance within (15) fifteen business days of receipt of the Force

Majeure notice provided under Paragraph 57. If the United States agrees that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay through the exercise of due diligence, the parties shall stipulate to an extension of the required deadline(s) for all requirement(s) affected by the delay for a period equivalent to the delay actually caused by such circumstances. Such stipulation shall be filed as a modification to this Consent Decree in order to be effective. Tampa Electric shall not be liable for stipulated penalties for the period of any such delay.

60. If the United States does not accept Tampa Electric's claim of a delay in performance, to avoid the imposition of stipulated penalties Tampa Electric must submit the matter to this Court for resolution by filing a petition for determination. Once Tampa Electric has submitted the matter, the United States shall have fifteen business days to file its response. If Tampa Electric submits the matter to this Court for resolution, and the Court determines that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay by the exercise of due diligence, Tampa Electric shall be excused as to that event(s) and delay (including stipulated penalties otherwise applicable), but only for the period of time equivalent to the delay caused by such circumstances.

61. Tampa Electric shall bear the burden of proving that any delay in performance of any requirement of this Consent Decree was caused by or will be caused by circumstances

beyond its control, including any entity controlled by it, and that Tampa Electric could not have prevented the delay by the exercise of due diligence. Tampa Electric shall also bear the burden of proving the duration and extent of any delay(s) attributable to such circumstances. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

62. Unanticipated or increased costs or expenses associated with the performance of Tampa Electric's obligations under this Consent Decree shall not constitute circumstances beyond the control of Tampa Electric or serve as a basis for an extension of time under this Section. However, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure event where the failure of the permitting authority to act is beyond the control of Tampa Electric and Tampa Electric has taken all steps available to it to obtain the necessary permit, including, but not limited to, submitting a complete permit application, responding to requests for additional information by the permitting authority in a timely fashion, accepting lawful permit terms and conditions, and prosecuting appeals of any allegedly unlawful terms and conditions imposed by the permitting authority in an expeditious fashion.

63. The parties agree that, depending upon the circumstances related to an event and Tampa Electric s response to such circumstances, the kinds of events listed below could also qualify as Force Majeure events within the meaning of this Section X of the Consent Decree: Construction, labor, or equipment delays; natural gas and gas transportation availability delays;acts of God; and the failure of an innovative technology approved under Paragraph 26.B and 52.C.

64. Notwithstanding any other provision of this Consent Decree, this Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of Tampa Electric delivering a notice pursuant to this Section or the parties' inability to reach agreement on a dispute under this Part.

65. As part of the resolution of any matter submitted to this Court under this Section, the parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the United States or approved by this Court. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

XI. DISPUTE RESOLUTION

66. The dispute resolution procedure provided by this Section XI shall be available to resolve all disputes arising under this Consent Decree, except as provided in Section X regarding Force Majeure, or in this Section XI, provided that the party making such application has made a good faith attempt to resolve the matter with the other party.

67. The dispute resolution procedure required herein shall be invoked by one party to this Consent Decree giving written notice to another advising of a dispute pursuant to this Section XI. The notice shall describe the nature of the dispute and shall state the noticing party's position with regard to such dispute. The party receiving such a notice shall acknowledge receipt of the notice, and the parties shall expeditiously schedule a meeting

to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

68. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations between the parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting between representatives of the United States and Tampa Electric unless the parties' representatives agree to shorten or extend this period.

69. If the parties are unable to reach agreement during the informal negotiation period, the United States shall provide Tampa Electric with a written summary of its position regarding the dispute. The written position provided by the United States shall be considered binding unless, within thirty (30) calendar days thereafter, Tampa Electric files with this Court a petition which describes the nature of the dispute and seeks resolution. The United States may respond to the petition within forty-five (45) calendar days of filing.

70. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Section may be shortened upon motion of one of the parties to the dispute.

71. This Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of invocation of this Section or the parties' inability to reach agreement.

72. As part of the resolution of any dispute under this Section, in appropriate circumstances the parties may agree, or this Court may order, an extension or modification of the schedule for completion of work under this Consent Decree to account for the delay that

occurred as a result of dispute resolution. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

73. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes; provided, however, that the United States and Tampa Electric reserve their rights to argue for what the applicable standard of law should be for resolving any particular dispute. Notwithstanding the preceding sentence of this Paragraph, as to disputes arising under Paragraph 32, the Court shall sustain the position of the United States as to the BACT Analysis recommendations and the optimization study measures that should be installed and implemented, unless Tampa Electric demonstrates that the position of the United States is arbitrary or capricious.

XII. GENERAL PROVISIONS

74. Effect of Settlement. This Consent Decree is not a permit; compliance with its terms does not guarantee compliance with all applicable Federal, State or Local laws or regulations.

75. Satisfaction of all of the requirements of this Consent Decree constitutes full settlement of and shall resolve and release Tampa Electric from all civil liability of Tampa Electric to the United States for the claims referred to in Paragraphs 43 and 44 of this Consent Decree. This Consent Decree does not apply to any claim(s) of alleged criminal liability, which are reserved.

76. In any subsequent administrative or judicial action initiated by the United States for

injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, Tampa Electric shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim splitting, or other defense based upon any contention that the claims raised by the United States in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to affect the enforceability of the Resolution of Claims provisions of Paragraphs 43 and 44 of this Consent Decree..

77. Other Laws. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Tampa Electric of its obligation to comply with all applicable Federal, State and Local laws and regulations. Subject to Paragraph 43 and 44, nothing contained in this Consent Decree shall be construed to prevent or limit the United States' rights to obtain penalties or injunctive relief under the Clean Air Act or other federal, state or local statutes or regulations.

78. Third Parties. This Consent Decree does not limit, enlarge or affect the rights of any party to this Consent Decree as against any third parties.

79. Costs. Each party to this action shall bear its own costs and attorneys' fees.

80. Public Documents. All information and documents submitted by Tampa Electric to the United States pursuant to this Consent Decree shall be subject to public inspection, unless subject to legal privileges or protection or identified and supported as business confidential by Tampa Electric in accordance with 40 C.F.R. Part 2.

81. Public Comments. The parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the requirements of 28 C.F.R. §

50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper, or inadequate.

82. Notice. Unless otherwise provided herein, notifications to or communications with the United States or Tampa Electric shall be deemed submitted on the date they are postmarked and sent either by overnight mail, return receipt requested, or by certified or registered mail, return receipt requested. Except as otherwise provided herein, when written notification to or communication with the United States, EPA, or Tampa Electric is required by the terms of this Consent Decree, it shall be addressed as follows:

As to the United States of America:

For U.S. DOJ

Chief
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DJ# 90-5-2-1-06932

Whitney L. Schmidt
Coordinator, Affirmative Civil Enforcement Program
Office of the United States Attorney
Middle District of Florida
400 N. Tampa Street
Tampa, FL 33602

For U.S. EPA

Director, Air Enforcement Division

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

and

Regional Administrator
U.S. EPA Region IV
61 Forsyth Street, S.E.
Atlanta, GA 30303

As to Tampa Electric:

Sheila M. McDevitt
General Counsel
Tampa Electric Company
P.O. Box 111
Tampa, FL 333601-0111

83. Any party may change either the notice recipient or the address for providing notices to it by serving all other parties with a notice setting forth such new notice recipient or address.

84. Modification. Except as otherwise allowed by law, there shall be no modification of this Consent Decree without written approval by the United States and Tampa Electric, and approval of such modification by the Court.

85. Continuing Jurisdiction. The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, or modification. During the term of this Consent Decree, any party may apply

to the Court for any relief necessary to construe or effectuate this Consent Decree.

86. Complete Agreement. This Consent Decree constitutes the final, complete and exclusive agreement and understanding among the parties with respect to the settlement embodied in this Consent Decree. The parties acknowledge that there are no representations, agreements or understandings relating to the settlement other than those expressly contained in this Consent Decree. An Appendix is attached to and incorporated into this Consent Decree by this reference.

XIII. TERMINATION

87. Except as provided in Paragraphs 43, 44, and 45 (involving resolution of claims), this Consent Decree shall be subject to termination upon motion by either party after Tampa Electric satisfies all requirements of this Consent Decree, including payment of all stipulated penalties that may be due, installation of control technology systems as specified herein, the receipt of all permits specified herein, securing valid Title V Permits for Gannon and Big Bend that incorporate all emission and fuel limits from this Consent Decree as well as all operational limits established under this Consent Decree, and the submission of all final reports indicating satisfaction of the requirements for implementation of all acts called for under Part VII of this Consent Decree.

88. If Tampa Electric believes it has achieved compliance with the requirements of this Consent Decree, then Tampa Electric shall so certify to the United States. Unless the United States objects in writing with specific reasons within 60 days of receipt of Tampa Electric s certification, the Court shall order that this Consent Decree be terminated on

Tampa Electric's motion. If the United States objects to Tampa Electric's certification, then the matter shall be submitted to the Court for resolution under Section XI of this Consent Decree. In such case, Tampa Electric shall bear the burden of proving that this Consent Decree should be terminated.

SO ORDERED, THIS _____ DAY OF ________________ 2000.

____

UNITED STATES DISTRICT JUDGE

Signature Page for Consent Decree in United States v. Tampa Electric Company,
Civ. No. 99-2524 CIV-T-23F

THROUGH ITS UNDERSIGNED REPRESENTATIVES, THE UNITED STATES AGREES AND CONSENTS TO ENTRY OF THE FOREGOING CONSENT DECREE:

FOR PLAINTIFF
UNITED STATES OF AMERICA:

______________________________ Date: ______________
Lois J. Schiffer
Assistant Attorney General
Environment and Natural Resources
Division
United States Department of Justice

____
W. Benjamin Fisherow
Assistant Chief
Thomas A. Mariani, Jr.
Jon A. Mueller
Senior Attorneys
Environmental Enforcement Section
United States Department of Justice
P.O. Box 7611
Washington, D.C. 20044
(202) 514-4620

Donna A. Bucella
United States Attorney for the
Middle District of Florida

By:______________________________
Whitney L. Schmidt
Affirmative Civil Enforcement Coordinator
Assistant United States Attorney
United States Attorney s Office
Middle District of Florida
Florida Bar No. 0337129
Tampa, Florida 33602
(813) 274-6000
(813) 274-6198 (facsimile)

Signature Page for Consent Decree in United States v. Tampa Electric Company,
Civ. No. 99-2524 CIV-T-23F

Steven A. Herman
Assistant Administrator for Office of Enforcement
and Compliance Assurance
U.S. Environmental Protection Agency
Washington, D.C.

Bruce Buckheit
Director

Gregory Jaffe
Senior Enforcement Counsel

Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Washington, D.C.

Signature Page for Consent Decree in United States v. Tampa Electric Company,
Civ. No. 99-2524 CIV-T-23F

John H. Hankinson
Regional Administrator
U.S. Environmental Protection Agency (Region IV)
Atlanta, Georgia

Signature Page for Consent Decree in United States v. Tampa Electric Company,
Civ. No. 99-2524 CIV-T-23F

THROUGH ITS UNDERSIGNED REPRESENTATIVES, TAMPA ELECTRIC COMPANY AGREES AND CONSENTS TO ENTRY OF THE FOREGOING CONSENT DECREE

FOR TAMPA ELECTRIC COMPANY

___________________________ Date: ____________
John B. Ramil
President
Tampa Electric Company

____
Sheila M. McDevitt
General Counsel
Tampa Electric Company

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park, NC 27711

EPA-454/R-00-039
September 2000

Air

CURRENT KNOWLEDGE OF PARTICULATE MATTER (PM) CONTINUOUS EMISSION MONITORING

Contains Data for
Postscript Only.

Current Knowledge of Particulate Matter (PM) Continuous Emission Monitoring

FINAL REPORT

For U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Emission, Monitoring and Analysis Division
Emission Measurement Center
Research Triangle Park, North Carolina 27711

Attn: Mr. Dan Bivins

EPA Contract No. 68-W6-0048
Work Assignment No. 3-07 and 4-03
MRI Project Nos. 104702-1-007-07-15
104703-1-003-07

September 8, 2000

PREFACE

This document was prepared by Midwest Research Institute (MRI) for the U. S. Environmental Protection Agency (EPA) under Contract No. 68-W6-0048, Work Assignments 3-07 and 4-03. Mr. Dan Bivins was the EPA Work Assignment Manager (WAM). This document summarizes the EPA's current knowledge of particulate matter continuous emission monitoring. The document consists of one volume with 98 pages and one appendix.

MIDWEST RESEARCH INSTITUTE

Craig Clapsaddle
Task Leader

Andrew Trenholm
Work Assignment Leader

Approved:

Joe Palausky
Program Manager

September 8, 2000

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EXECUTIVE SUMMARY

Continuous monitoring of particulate matter (PM) concentrations in smoke stacks started during the 1960s in Germany and became a German Federal requirement in the mid 1970s. In the United States, PM concentrations were correlated to opacity monitor readings during the 1970s. Then, in the mid 1970s, the EPA dictated the use of transmissometers for continuous monitoring of the opacity of emissions from sources. Opacity is used as a surrogate for PM emissions and provides qualitative information on the operation and maintenance of particulate control equipment. Continuous particulate mass monitoring was proposed as an EPA regulatory requirement on April 19, 1996, as part of the proposed Hazardous Waste Combustion MACT standard (61 FR 17358). The EPA also proposed performance specification (PS)-11, Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems in Stationary Sources, to evaluate the acceptability of a PM continuous emission monitoring system (CEMS). The Portland Cement Manufacturing MACT Final Rule (64 FR 31898, June 14, 1999) in section 63.1250(k) makes mandatory the use of PM CEMSs although not until the EPA has finalized PS-11.

Five analytical principles (light scattering, beta attenuation, probe electrification, light extinction, and optical scintillation) used in instruments to measure PM concentrations are described in this document. The following monitors are described in detail and are commercially available from manufacturers as “off-the-shelf” PM continuous emission monitors:

Durag F904K Beta Attenuation
Environment S.A. 5M Beta Attenuation
Mechanical Systems Inc. BetaGuard PM Beta Attenuation
Sigrist KTNR and CTNR Extractive Light Scatter
Durag DR-300-40 In-situ Light Scatter
Environmental Systems Corporation P5 In-situ Light Scatter
Sick Inc. RM210 In-situ Light Scatter
Sick Inc. FW 100 and FWE 200 Light Scatter
Grimm Technologies Inc. Model 6300 In-situ Light Scatter
Monitor Labs Model 300L In-situ Light Scatter
BHA Group CPM 5000 Scintillation

PCME Scintilla SC600 Scintillation
Insitec TESS In-situ or Extractive Laser Light Extinction-Scatter
PCME DustAlert 90 Electrostatic Induction
Auburn International Triboguard III or II In-situ Triboelectric
Codel StakGard Triboelectric Dust Monitor

Several opacity monitors are included for completeness.

PS-11 is used for evaluating the acceptability of an installed PM CEMS. This performance specification requires site-specific correlation of the PM CEMS response against manual gravimetric EPA Methods. PS-11 outlines the procedures and acceptance criteria for installation and operation of instrumentation and for calculations and reporting of data generated during a PM CEMS correlation. PS-11 is unique, relative to the performance specifications for other CEMS, because it is based on a technique of correlating a PM CEMS's response to emissions determined by the manual PM method. In conjunction with PS-11, Procedure 2, which was also proposed in 1996 with PS-11, stipulates the quality assurance (QA) and quality control (QC) measures that must be applied to a PM CEMS.

In Germany to meet regulatory monitoring requirements for a particular industry type, a specific model PM CEMS must pass a suitability test and be approved by the German Federal Environmental Agency before it can be installed and used as a PM CEMS. The suitability test consists of both a laboratory evaluation and a field evaluation. The United Kingdom has a similar approval mechanism for a PM CEMS.

The EPA and industry have done the following recent field evaluations of PM CEMS:

- EPA/Office of Solid Waste (OSW) – 3 PM CEMSs at a mixed solid and liquid hazardous waste incinerator located in Bridgeport, New Jersey during March 1995.
- EPA/OSW – 2 PM CEMSs at a hazardous waste cement kiln located in Fredonia, Kansas during May through July 1995.
- EPA/OSW – 5 PM CEMSs at the DuPont Experimental Station's hazardous waste incinerator located in Wilmington, Delaware during September 1996 through May 1997.
- Electric Power Research Institute – 4 PM CEMSs at Georgia Power Company's Plant Yates coal-fired boiler located in Newnan, Georgia during June through September 1998.

- Eli Lilly, the Chemical Manufacturers Association, and the Coalition for Responsible Waste Incineration – 2 PM CEMSs at a liquid hazardous waste incinerator at the Eli Lilly Clinton Lab in Clinton, Indiana during February through June 1998 and November through December 1998.
- EPA/OAQPS – 3 PM CEMSs at a coal-fired boiler located in Battleboro, North Carolina during June 1999 through February 2000.

Results of the EPA and industry field evaluations are described in this document.

1.0 INTRODUCTION

This report provides detailed information on the current knowledge of PM CEMSs. This information was gained from literature reviews; attendance at many meetings and conferences where the use of PM CEMSs was discussed; shared knowledge between the EPA, industry, and consultants experienced with PM CEMSs in both the United States and Europe; discussions with PM CEMS vendors; and personal experiences from performing a field demonstration of PM CEMSs. The report will be maintained as a "living document" with periodic updates as needed.

The report is primarily written to provide information useful to State permitting authorities and EPA Regional personnel. However, the information contained herein will be useful to all persons involved with a PM CEMS program. It includes (1) technical information on the monitors and their principal of operation, (2) their use history, (3) a summary of recent PM CEMS field demonstrations, (4) recommendations for future field demonstrations, (5) recommendations on how to implement a PM CEMS program, (6) a summary of the performance specification for PM CEMSs, and (7) cost information.

A draft of this report was sent to 14 individuals with different view points and knowledge in the field of continuous PM monitoring. The EPA received comments from nine reviewers, and their comments were incorporated into this final report.

2.0 HISTORICAL PERSPECTIVE OF CONTINUOUS PM MONITORING

2.1 OVERVIEW OF REGULATORY USE

Continuous monitoring of PM concentrations in smoke stacks started during the 1960s in Germany. In the United States during the 1970s, PM concentrations were correlated to opacity monitor readings, but the EPA dictated the use of transmissometers to continuously monitor the opacity of emissions from sources. For the EPA's emission monitoring regulations and State Implementation Plans (SIP), opacity is used as a surrogate for PM emissions and provides qualitative information on the operation and maintenance of particulate control equipment. The EPA's New Source Performance Standards (NSPS) require continuous monitoring of opacity of emissions from the 11 source categories presented in Table 2-1.

TABLE 2-1. NSPS REQUIRING COMS

Source category	40 CFR Part 60 Subpart
Electric Power Plants	D, Da, Db, Dc
Portland Cement Plants (Kiln and Clinker cooler)	F
Petroleum Refineries (FCCU)	J
Primary Copper Smelters (Dryer)	P
Primary Zinc Smelters (Sintering machine)	Q
Primary Lead Smelters (Blast furnace, Dross reverberatory furnace, and Sintering machine)	R
Ferroalloy Production (Control device)	Z
Electric Arc Furnace in steel mills (Control device)	AA
Kraft Pulp Mills (Recovery furnace)	BB
Lime Kilns (Rotary lime kiln)	HH
Phosphate Rock Plants (Dryer, Calciner, Grinder)	NN

In Germany, the first laws to require continuous monitoring of PM emissions came on December 29, 1959 in the German Federal Law for Citizens (Act to Amend the Industrial Code..., 1959). Then in 1964, a more concrete requirement for continuous PM monitoring that included many types of industrial plants was amended in the Technical Instruction for Air Pollution Control

(TA Luft, 1964). Plants with emissions exceeding 55 pounds per hour were required to continuously monitor PM concentration in mg/acm "as soon as a suitable instrument becomes available." The requirements in TA Luft of 1964 initiated field studies of continuous PM emission monitoring instrumentation. Several field-based research projects were completed by the German federal government in the years following the German Federal Law of Environmental Protection (BlmSchG, March 15, 1974). These field studies were completed to correct deficiencies found in the measurement technology and formed the basis for the German's instrument approval process (see Section 2.3). Additional legislative rules detailed the monitoring requirements for power plants (13th BlmSchV, 1983) and waste incinerators (17th BlmSchV, 1990) (Breton, 1989, Martin, 1994, Jockel, 1998, and Jockel, 1999).

In the United States in 1975, the EPA promulgated Performance Specification - 1 (PS-1), Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources, to govern the design, performance, and installation of COMS (40 FR 64250, October 6, 1975). In 1983, the EPA amended PS-1 (48 FR 13322, March 30, 1983), and in 2000, the EPA amended PS-1 again by incorporating ASTM D6216-98 design and monitor manufacturer performance specifications (65 FR 48914, August 10, 2000).

Continuous particulate mass monitoring was proposed as an EPA regulatory requirement April 19, 1996, as part of the proposed Hazardous Waste Combustion MACT emission standard (61 FR 17358). As part of the Hazardous Waste Combustion MACT, the EPA proposed PS-11, Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems in Stationary Sources, to evaluate the acceptability of a PM CEMS. The Portland Cement Manufacturing MACT Final Rule in section 63.1250(k) (64 FR 31898, June 14, 1999) makes mandatory the use of PM CEMSs although not until the EPA has finalized PS-11.

2.2 PAST STUDIES

During the 1970s, the EPA sponsored several studies to examine the applicability of transmissometers to sources and the potential to correlate opacity to PM mass concentrations. Some of those studies are summarized below. Into the 1980s, philosophies changed within the EPA, and continuous PM monitoring was not a priority. Work on the PM CEMS in this country stopped until new initiatives started in the mid 1990s.

In a 1974 publication from the EPA's National Environmental Research Center, Conner (1974) showed that smoke's opacity is related to (1) the size of the particles and (2) the light wavelength used by a transmissometer. Particles much smaller than the light wavelength (particle diameter < 0.05 µm in white light) contribute little to the opacity (extinction coefficient < 0.01). For particles much larger than the light wavelength (particle diameter > 2 µm in white light), the opacity is not a function of the light wavelength, and the mean extinction coefficient is about 2. For particles about the same size as the light wavelength (0.05 < d < 2 µm in white light), opacity has a strong dependence on the particle diameter, that is, the extinction coefficient increases from 0.01 to as high as 3 or 4 as the particle diameter increases from 0.05 µm to 2 µm. Also, Conner detailed the effect of a transmissometer's light wavelength on the opacity of fine particles (Conner et al., 1967). Opacity determined from a blue light source has a positive bias (e.g., in a white plume, an opacity of 25 percent, as determined by white light, is seen as about 40 percent by blue light), and opacity determined from a red light source has a negative bias (e.g., in a white plume, an opacity of 25 percent, as determined by white light, is seen as about 18 percent by red light). Opacity determined from an infrared light source has a strong negative bias (e.g., in a white plume, an opacity of 25 percent, as determined by white light, is seen as about 5 percent by infrared light). A black plume demonstrates the same biases but to a lesser degree.

As of 1974, the EPA had not resolved a transmissometer's ability to monitor PM mass concentrations from sources. Some investigators reported good empirical correlations between mass concentration and light transmittance while others indicated that the effect of particle characteristics on the correlation was too strong for a meaningful correlation. At that time, the researchers clearly understood that for a useful correlation to exist between opacity and PM mass concentration, the particle characteristics (size, shape, and composition) needed to be sufficiently consistent and to remain consistent over time (Conner, 1974). Conner (1974) showed mass concentration versus opacity for a kraft pulp mill recovery furnace, a cement plant kiln, and a coal-fired boiler. The concentration versus opacity graphs showed that a strong linear relationship existed between mass concentration and opacity at those three sources. Conner noted that particulate emission control devices would likely control the particulate characteristics that most affect the opacity to mass concentration correlation sufficiently enough that a transmissometer could be used as a mass monitor.

In a 1975 journal article, John Nader, Chief of the Stationary Source Measurements Research Section of the EPA's National Environmental Research Center, published a summary of the current technologies for continuously monitoring PM emissions. In his paper, he discussed electromagnetic techniques, beta attenuation techniques, optical techniques (both light attenuation and light scatter), and electrical techniques. At the time his paper was published, most of the instruments were prototypes. Nader concluded that a performance specification for particulate mass concentration monitors would be developed in the near future.

In a 1979 publication from the EPA's Environmental Sciences Research Lab, Conner, Knapp, and Nader (1979) presented, in addition to other things, the existence of a functional relationship between in-stack transmissometer-measured opacity and mass concentration of PM emissions. This examination was done at Portland cement plants and oil-fired power plants. Their paper contained the following equation that demonstrates that the opacity-mass concentration relationship depends on the chemical and physical characteristics of the particles, as well as the pathlength of the opacity measurement:

$$O = 1 - e^{-AC\ell}$$

where:

O = opacity

A = attenuation per unit path length per unit mass concentration

C = mass concentration

ℓ = pathlength of opacity measurement

Tests to correlate opacity and mass concentration were done at three cement plants; two used the wet-process rotary kiln with PM emissions controlled with ESPs and one used the dry-process rotary kiln with a baghouse for PM emissions control (Conner, Knapp, and Nader, 1979). Opacity measurements were made with either a Lear Siegler RM4 or RM41P. Mass concentrations were determined by EPA Reference Method 5. The results of their study indicate that the light attenuation coefficient of PM emissions at cement plants is linearly related to the PM mass concentration for both wet and dry processes. However, for the correlation done at actual stack conditions, the slopes of the curves (attenuation coefficient/mass concentration) were distinctly different for the wet process (1.55±0.02 $m^{-1}/g/m^3$) and the dry process

(0.92 ± 0.08 $m^{-1}/g/m^3$). Note, the correlation for the process controlled by the baghouse was developed from only three data points within a narrow opacity range of about 6 percent to 8 percent. This suggests caution when interpreting these results.

Other tests to correlate opacity and mass concentrations were done at three oil-fired power plants (Conner, Knapp, and Nader, 1979). The boilers had no PM emission control equipment installed. Two plants combusted low-sulfur oil, and the boilers were fired at excess oxygen levels between 1.5 percent and 3.0 percent. The third plant combusted high-sulfur oil, and the boiler excess oxygen was at 0.2 percent. Opacity measurements were made with a Lear Siegler RM41P. Mass concentrations were determined by EPA Method 5. The data from the two similar plants were combined, and a light attenuation coefficient per mass concentration ratio (at actual stack conditions) of 0.43 $m^{-1}/g/m^3$ was calculated. This relationship was calculated over an opacity range from about 2.5 percent to 6.7 percent and forced through the origin. The data for the high-sulfur, oil-fired boiler produced a light attenuation coefficient per mass concentration ratio (at actual stack conditions) of 0.20 $m^{-1}/g/m^3$. This relationship was calculated from data collected during two sampling efforts 6 months apart covering an opacity range from about 6 percent to 11 percent. This relationship was also forced through the origin. The authors stated their reason for the difference in the correlations as follows: the low excess oxygen combustion produced a greater portion of particles (unburned carbon) in the large size fraction (mean diameter of about 3 µm compared to less than 0.3 µm) and therefore, as expected, produced lower opacity readings.

In a 1980 article, Uthe published the results of an evaluation of a relatively inexpensive infrared transmissometer used as a PM mass concentration monitor. Uthe's results showed that the extinction-to-mass concentration for a given aerosol type is dependent on particle size within the visible light spectrum but nearly independent of particle size at the infrared wavelength. Uthe tested his IR transmissometer in an aerosol chamber with three distinct particle size ranges: 0-2.5 µm, 2.5-5 µm, and 5-10 µm. His particles were composed of fly ash, iron oxide, and silica. For fly ash particles in the size range of 0-10 µm, the IR extinction to mass concentration ratio varied by a factor of 1.6 while the variability for visible light was a factor of 4.4. For silica particles, the IR extinction to mass concentration ratio was nearly constant while the variability for visible light was about a factor of 3. Personal communication with Uthe revealed that the IR transmissometer was never evaluated on a real emission source.

During a 1-year period in 1976-1977, a group of researchers from the Industrial Research Institute, University of Windsor (Gnyp et al., 1978), conducted a field evaluation of five different PM monitors. The test was done at a secondary lead smelter. The stack exhaust consisted of particulate from uncontrolled lead alloying kettles and a reverberatory furnace controlled with a fabric filter. Thirty-two PM test runs were conducted over a 9-month period from June 4, 1976 to March 7, 1977. Twelve tests accounted for the reverberatory furnace mode of operation (i.e., controlled emissions). The remaining 20 tests were conducted while refining processes were in progress (i.e., uncontrolled emissions). The arithmetic mean particle diameter of the baghouse emissions was 0.43 µm with a standard deviation of 0.13 µm. The arithmetic mean particle diameter of the emissions from the lead kettles was 18.9 µm with a range from 0.05 µm to 150 µm. The particulate consisted primarily of lead, tin, and zinc. The results of the PM monitor evaluation are summarized in Table 2-2.

TABLE 2-2. PM MONITOR EVALUATION RESULTS
AT A SECONDARY LEAD SMELTER

PM monitor	Results
Lear Siegler RM41 transmissometer	Impossible to correlate all 32 tests to one curve
	Three distinct linear correlations were evident
	Most reliable of all monitors tested
	Not applicable for sources where process variations cause changes in PM size, color, or refractive indices
Contraves Goertz with RAC transmissometer	Impossible to correlate all 32 tests to one curve, basically the same results as the RM41
	Not capable of detecting large particles greater than 25 µm in diameter
Environmental Systems Corporation PILLS V light scatter monitor	Correlation was relatively independent of changes in particle size, color, and refractive index
	More useful than the best transmissometers
	Some of the variability in the data was attributed to changes in absorptive components of refractive indices

TABLE 2-2. (CONTINUED)

PM monitor	Results
IKOR 2710 charge transfer	Limited sensitivity to particles smaller than 1 μm diameter; particles must contact sensor
	At the stack conditions, only particles larger than 4 μm in diameter made contact with the sensor surface
	Orienting the sensing element with its axis perpendicular to the flow did not improve the contact of small particles
Research Appliance Co. (RAC) beta gauge monitor	Expected a single correlation curve, but instrument was more sensitive to smaller particles less than 1 μm in diameter
	Substantial amounts of PM were recovered from the sampling system at the end of the test program
	Experienced many operational breakdowns, only functioned for 13 test runs

The developmental testing of PM CEMSs in Germany started during the 1960s when the TÜV-Rheinland (the German "technical inspection agency," a not-for-profit organization similar to Underwriters Laboratories in the United States) first investigated continuous PM monitors (Draft Technical Support Document, 1996). The early tests involved transmissometers. Initially, eight devices were evaluated, but all failed to perform to the satisfaction of TÜV. After improvements were made, TÜV Rheinland certified two transmissometers in 1968 (Peeler et al., 1995). The first certification of a PM CEMS (a transmissometer) was issued in 1974 and prompted the German Federal Law of Immission Protection to require continuous monitoring of PM emissions at power plants. A further reduction in particulate emissions was required with the passage of the First Regulation of General Administration Procedures to the Federal Law of Immission Protection on February 27, 1986. This latter act spurred the use of more sensitive monitors to measure PM emissions from well-controlled waste incinerators.

As previously noted, during the early period of continuous PM monitoring in Germany, transmissometers were used to measure extinction ($b = 2.303 * \log(1/T) / PL$) and were correlated to PM concentration. A key advantage of using extinction rather than opacity is that extinction relates linearly to particulate matter. Extinction also results in an output that is more sensitive to increases in PM concentration at low levels. The transmissometers were typically operated at two measuring ranges, 0-9 percent or 0-33 percent opacity. For a 1-meter pathlength, a transmissometer's minimum quantifiable PM concentration is about 30 mg/acm (Peeler et al., 1995). From 1968 through 1985, approximately 1,000 to 2,000 transmissometers, measuring extinction, were installed on all types of sources in Germany measuring PM emission limits in the range of 30 mg/m^3 to 150 mg/m^3. Furthermore, approximately 5,000 transmissometers, measuring opacity, were installed for monitoring control equipment performance. Then, as PM concentrations decreased to levels too low to be accurately measured with transmissometers, use of the light scattering type PM CEMS came into favor. Light scatter monitors are 100 to 1,000 times more sensitive than transmissometers. A light scattering monitor's output is directly proportional to PM concentration, and thus inversely proportional to a transmissometer output (i.e., it cannot be used as a substitute for an opacity monitor). Since 1986, light scatter monitors represent about 80 percent of new PM monitors installed in Germany (Peeler et al., 1995). During the 1990s, many existing transmissometers were replaced with light scattering type PM CEMS as facilities updated their pollution control equipment to come into compliance with more stringent regulations. The suitability testing for transmissometers is governed by VDI Guideline 2066, Part 4. The suitability testing of light scattering type PM CEMSs is governed by VDI Guideline 2066, Part 6.

2.3 CURRENT EUROPEAN EXPERIENCE

In Germany, a specific model PM CEMS must pass a suitability test and be approved by the Federal Environmental Agency before it can be installed and used as a PM CEMS to meet regulatory monitoring requirements. The suitability test follows guidelines in a Standard Practice regarding the monitoring of emissions (Standard Practice, 1990, revised June 8, 1998). The source-specific acceptance of a suitability test is based on a hierarchy of difficulty in passing the test; incinerators are most difficult, followed by coal, oil, and gas-fired plants. Thus, if a monitor passes suitability for an incinerator, the monitor is also approved for all the less difficult sources. However, sources such as cement kilns and metal recovery furnaces are separate and require their own suitability test (Draft Technical Support Document, 1996). The specifications that a PM monitor must meet to gain approval are presented in Table 2-3. The suitability test consists of both a laboratory evaluation and a field evaluation. In most cases, the suitability test is done by the TÜV branch in Rheinland; however, TÜV is not the only organization that can do the suitability test.

TABLE 2-3. GERMAN SUITABILITY TEST SPECIFICATIONS FOR APPROVAL

Test	Specification[a]
Normative conditions	Suitability testing must be done according to guidelines in VDI 2449 part 1 dated February 1995.
Endurance test	Conduct an endurance test for at least 3 months. If possible, conduct the test at a single test site for a continuous period.
Analytical function	In suitability testing, the relationship between the instrument reading and mass concentration from a reference measuring method must be determined by regression analysis. Each instrument must be supplied with a characteristic curve plotted by the manufacturer.
Protection from changing settings (Security)	The instrument and control units must be secured against unauthorized or inadvertent change during operation.
Zero and reference point position	The zero point should be 10 percent to 20 percent of full scale on the instrument display and recording device. The reference point should be 70 percent to 90 percent of full scale.
Full scale readout range	The readout range should equal: • 2.5 to 3 times the applicable emission limit for a coal-fired furnace • 1.5 times the applicable emission limit for a waste incinerator
Measured value output	The instrument must have two readout channels.
Status signals	The instrument must have status signals for 1. Operation 2. Service 3. Malfunction
Availability	The instrument must achieve 90 percent data availability during continuous operation and 95 percent availability during the evaluation test.
Maintenance interval	The instrument's maintenance period must be at least 8 days (i.e., no operator intervention for at least 8 day intervals). Maintenance period is determined during the field evaluation.
Reproducibility - for all PM CEMS since 1998	$R_D \geq 50$ for a measuring range ≥ 20 mg/m^3 $R_D \geq 30$ for a measuring range < 20 mg/m^3
Complete system	The suitability test covers the entire CEMS.

TABLE 2-3. (CONTINUED)

Test	Specification[a]
Normal operating conditions	Evaluate the instrument under the following conditions over the manufacturer's recommended range for each: 1. Supply voltage variation 2. RH in ambient air 3. Liquid water in the air 4. Vibration and shock
Automatic readjustment	For instruments with self-testing of proper operation and automatic readjustment, test these features in the evaluation test. If an adjustment range of ±6 percent of span is exceeded during autocorrection, an alarm must be given.
Ambient temperature range	For instruments installed unprotected from ambient conditions, the instrument must operate over the range of -20^{o}C to 50^{o}C. For temperature-controlled installations, the instrument must operate over the range of 5^{o}C to 40^{o}C. Test instrument in a climate chamber.
Effect of sample gas flow	For instruments using a bypass for sampling, the effect of changes in sample gas flow rate on the measured signal must not exceed ±1 percent of span. Neither the total volumetric flow sampled during the operating cycle nor the dilution air volumetric flow may deviate from the expected value by more than ±8 percent.
Multicomponent instrument	Each component must fulfill the requirements, even when all measuring channels are operating simultaneously.
Drift between servicing intervals	The zero point must not drift more than ±2 percent of full scale for range ≥ 20 mg/m^3 ±3 percent of full scale for range < 20 mg/m^3 The reference point must not drift more than ±2 percent of the reference value for range ≥ 20 mg/m^3 ±3 percent of the reference value for range < 20 mg/m^3
Linearity	The difference between the actual value and the reference value must not exceed ±2 percent of full scale (for a 5 point check).
Contamination check	If the measurement principle depends on optical methods, the instrument must check for optical surface contamination during operation. Use clean purge air to keep optical surfaces clean.
Outward migration of measurement beam	If the measurement principle is based on optical methods, any impairment due to outward migration of the measurement beam must be stated and must not exceed 2 percent of full scale in an angular range of ±0.3°.

TABLE 2-3. (CONTINUED)

Test	Specification[a]
Automatic correction of zero and reference points	The instrument must automatically initiate and record the zero and reference points at regular intervals. For instruments with automatic zero point correction, the correction amount must be recorded as a measure of contamination.
Exhaust gas volume	For extractive instruments, the sample volume must be within ±5 percent of the set point.
Dead time, setting time (similar to cycle time)	Measure the dead time to include: response time, analysis time, and reporting time.

[a] Specifications derived from TÜV Suitability Test Reports for the Sigrist CTNR, Verewa F-904, and Durag D-R 300-40.

After a PM CEMS is installed, its output is correlated to manual gravimetric particulate data. The stability of the correlation is checked by conducting additional manual gravimetric tests at 3- to 5-year intervals, depending on the source type. A linearity check of the instrument's response is also done annually (Peeler et al., 1995). The TÜV has guidelines for establishing correlation curves. Most of the manual particulate emissions measurements are done by an isokinetic, in-stack filter test method (similar to Method 17 - VDI 2066, Part 7); however, in-stack sampling is limited to stacks with no entrained water droplets. The following guidelines are used for a correlation test in Germany (personal communication with Dr. Wolfgang Jockel, TÜV, Rheinland):

- The test program consists of 12 to 20 test runs.
- A few paired train test runs are completed to demonstrate an ability to maintain precision. If the testing team has experience at a source, they do not do any test runs with paired trains.
- Test runs are short, no longer than 30 minutes (this is so that any variability in PM concentrations is noticeable and not averaged out by a long test run).
- If the facility cannot achieve any variability in PM concentration, the correlation test program is stopped after 6 test runs. Typically, waste combustion facilities have extensive air pollution control systems (e.g., a water spray drier for cooling, a fabric filter, an acid gas (HCl) scrubber, a lime scrubber SO_2 control, a dual catalyst SCR and dioxin oxidizer,

and an activated charcoal “police” filter), and the particulate emissions cannot be artificially adjusted to obtain a range of PM concentrations.

In cases with emissions that are very low relative to the limit, the guidelines allow extrapolation of the correlation; however, data measured beyond the correlation range trigger only additional testing, not noncompliance. For a correlation data set with only a cluster of data points very much below the emission limit, the emission limit becomes related to the mA signal of the PM CEMS. For example, if a PM CEMS output during the testing ranged from 4 mA to 4.5 mA, no 30-minute average may exceed 4.5 mA during plant operations. If an average exceeds 4.5 mA, a new correlation test that includes values above 4.5 mA would have to be done. For a limited correlation data set with little variability in PM concentration, the German guidelines require the use of a hypothetical zero point (i.e., 4 mA = 0 mg/m^3) in the correlation data set for an in-situ light scatter type PM CEMS using little or no purge air and for an extractive type PM CEMS (i.e., either beta gauge or light scatter).

The German approach to using a PM CEMS is to build the statistical uncertainty of the PM CEMS measurement (due to the factors of particle composition and size distribution) into the emission limit value. The correlation relation is not required to achieve a specific statistical accuracy (e.g., a confidence interval ≤10 percent at the emission limit value) to be approved. This approach is illustrated in the following example. A municipal waste combustion facility has a base PM emission limit (EL) of 30 mg/dscm. Assume a specific source’s PM CEMS correlation has a confidence interval (CI) at the emission limit of 4 mg/dscm (13 percent) and a tolerance interval (TI) at the emission limit of 11 mg/dscm (37 percent). Then, that specific source would have the following PM limitations (from personal communication with Dr. Wolfgang Jockel, TÜV, Rheinland):

- No 30-minute average may exceed: 2*EL + TI = 60 + 11 = 71 mg/dscm.
- 97 percent of the annual 30-minute averages may not exceed: 1.2(EL + CI) = 36 + 5 = 41 mg/dscm.
- No daily average may exceed: EL + CI = 30 + 4 = 34 mg/dscm.

Even with the uncertainty in the PM CEMS measurement, the correlation relationship can still be used as a basis for compliance. Traditionally, the EPA regulations have taken this uncertainty into account when a CEMS-based standard is adopted.

In addition to the suitability testing specifications that exist in Germany, the International Standards Organization (ISO) has developed standards for PM CEMSs. The ISO committee TC146/SC1/WG1 finalized ISO 10155 "Stationary Source Emissions - Automated Monitoring of Mass Concentrations of Particles - Performance Characteristics, Test Methods, and Specifications" on April 1, 1995. ISO 10155 specifies conditions and criteria for the automated monitoring of PM mass concentrations in stationary sources. The specifications are general and not limited to a specific measurement principle or system. The Central European Normalization (CEN) Committee TC264/WG5 has developed requirements applicable to continuous PM monitoring. CEN adopted ISO 10155 for hazardous waste incinerators.

The Environment Agency (EA) in the United Kingdom (UK) has established a monitoring certification scheme (MCERTS) for all CEMSs, including PM CEMSs. The MCERTS program is similar to the program used in Germany and began on April 22, 1998. The performance standards have been specified for the following sources:

- Large combustion plants
- Municipal and hazardous waste combustors
- Solvent-using processes

The instrument performance standards are based on relevant sections of several ISO and CEN standards. These standards are published as EA standards under the MCERTS program. Instrument testing is done in two parts; laboratory tests and a 3-month field evaluation. The standards cover the performance characteristics presented in Table 2-4.

TABLE 2-4. MCERTS PM CEM EVALUATION CHARACTERISTICS

Laboratory test	Field evaluation
Use a wind tunnel test with well characterized and reproducible particle-size distribution with mass concentration variable from 0 to 500 mg/m^3 at a gas flow velocity of 1.5 to 50 ft/s	Accuracy - as calibrated according to ISO 10155
Response time	Reproducibility from two identical PM CEMS
Calibration to PM generated in wind tunnel	Zero and upscale drift during the field test period - average of daily drifts over a month
Linearity of PM CEM response to changes in PM concentration at 5 levels	Data availability

TABLE 2-4. (CONTINUED)

Laboratory test	Field evaluation
Cross-sensitivity to gases, velocity changes at a fixed PM concentration, and particle size changes	Maintenance interval - time over which the zero and upscale drifts remain within specification
Establishment of a lower detection limit	
Repeatability of the PM CEM's output to a continuous PM concentration in tunnel	
Change in zero value to variations in • Ambient humidity • Ambient temperature • Vibration • Mechanical shock • Magnetic field • Aging	

3.0 ANALYTICAL PRINCIPLES

Five analytical principles used in instruments to measure PM concentrations are described below. These principles are light scattering, beta attenuation, probe electrification, light extinction, and optical scintillation.

3.1 LIGHT SCATTERING

Light is both absorbed and scattered by particles in the path of the light. Scattering is due to reflection and refraction of the light by the particle. The amount of light scattered is based on the concentration of particles and the properties of the particles in the light's path (e.g., the size, shape, and color of the particles). If the wavelength of the incident light is much larger than the radius of the particle, a type of scattering called "Rayleigh" scattering occurs. Rayleigh scattering causes the blue color of the sky because visible sunlight is scattered by very small particles and gases in the upper atmosphere. If the wavelength of the incident light is about the same size as the radius of the particle, a type of scattering called "Mie" scattering will occur. Mie scattering causes the haze seen on a hot summer day and the reduction of visibility by car headlights in a fog.

A light scatter type instrument measures the amount of light scattered in a particular direction (i.e., forward, side, or backward) and outputs a signal proportional to the amount of scattering material (e.g., particulate matter) in the sample stream. The PM concentration is derived by correlating the output of the instrument to manual gravimetric measurements. In a scatter light instrument, a collimated beam of visible or near infrared (IR) light is emitted into a gas stream. The light is scattered by particles in the light path (i.e., Mie scattering), and the receiving optics focus an area of that light onto a detector that generates a current proportional to the intensity of light it receives. The angle of the source to the receiving optics and the characteristics of the optics determine the volume of space from which the scattered light is measured.

Some components included in these instruments to minimize the effect of interference and degradation of the light source are: (1) the use of a pulsed light and (2) parallel measurement of the light source intensity. The use of the pulsed light source limits the possibility that light from some other source (e.g., ambient light) will be measured, because the instrument only measures the reflected light while the instrument light source is on. The parallel measurement of the light source intensity accounts for degradation of the light source because a reference of the source intensity is measured along with each scattered light measurement.

3.2 BETA ATTENUATION

When beta rays pass through a material, they can be absorbed, reflected or pass directly through. The attenuation of intensity in beta rays is proportional to the amount of material present. The attenuation through most materials is relatively consistent and is based on the electron density of the material (calculated by dividing the atomic number by the atomic mass). The attenuation for most materials is about 0.5, except for hydrogen and heavy metals. Beta attenuation has been used in production lines as a quality control check of product thickness for more than 40 years. For example, in the production of cellophane plastic wrap, a beta gauge is used to ensure that the thickness of the cellophane remains within specification.

The principle behind beta attenuation particulate sampling instruments (beta gauge) is that energy is absorbed from beta particles as they pass through PM collected on a filter media. Beta gauge instruments have been designed to take advantage of this scientific principle to monitor/measure PM concentrations. The attenuation due to only the PM is measurable if a baseline beta count through just the filter can be established prior to sampling. The difference between the baseline beta count and the beta count after sampling is directly proportional to the mass of PM in the sample.

The two main components of a beta attenuation measuring system are the beta source and the detector. The beta source must be selected so that: it has an energy level high enough for the beta particles to pass through the collection media (i.e., the filter tape) and the particulate, it has enough source material so that a high count rate is present, it is stable over long periods of time, and it does not present a danger to the health of personnel that come into contact with the instrument. The source of choice has been Carbon-14 because: it has a safe yet high enough energy level, it has a half-life of 5,568 years, and it is relatively abundant. Many different types of detectors can quantify beta particle counts, but the ones most widely used are the Geiger Mueller counter or a photodiode detector.

The beta gauge works by measuring beta counts before and after collecting PM on a filter media. The instrument will measure a clean area of the filter media for a fixed period to determine the baseline (e.g., 2 minutes), then it will advance that area of the filter to a sampling apparatus for another set period of time (e.g., 8 to 9 minutes), and finally return that area of the filter to the detector for the same period used to establish the baseline reading. The difference in the beta count can be directly correlated to particulate mass through calibration of the instrument using a filter media containing a known mass of a particulate-like material.

The beta gauge instrument is designed to provide a mass concentration. The instrument measures the volume of gas extracted from the stack/duct for each sample interval and calculates mass concentration in the specified units (e.g., mg/dscm).

3.3 PROBE ELECTRIFICATION (TRIBOELECTRIC EFFECT)

Probe electrification takes advantage of the fact that all particles have a charge. Electrostatic charges from the friction of particles contacting a probe will electrify the probe (i.e., a small current is produced in the probe). This is called triboelectricity. Another applicable mechanism is based on a small current being induced in the probe when charged particles pass near a probe.

A triboelectric particulate monitoring device measures the direct current (DC) produced by the charge transfer when particles strike the probe. The DC is measured by an electrically isolated sensor probe that is connected to amplification electronics. Multiple particle strikes create a small flow of current through the instrument; current is proportional to the momentum (mass times velocity squared) of the particles. Amplification electronics convert the current to an instrument output signal. Monitors that rely on inducing a current in the probe, rather than particle contact with the probe, work similarly except an alternating current (AC) is measured.

Because the signal produced by these monitors may be affected by several factors, the instrument output must be correlated to manual gravimetric measurements. Some of the primary factors that may affect the relationship between particle mas and the monitored signal are particle velocity for triboelectric devices, particle characteristics (e.g., composition and size), and particle charge. Probe electrification does not work well in wet gas streams with water droplets or when the particles are subject to a varying electrical charge. The AC component of the induced current is being used to minimize the effect of velocity on the measurement.

3.4 LIGHT EXTINCTION (TRANSMISSOMETER)

Light extinction is a common method in use today; the instruments that incorporate this technology are referred to as transmissometers or opacity monitors. These instruments measure the loss of light intensity across a particulate laden gas stream as a function of Beers-Lambert's Law. The intensity of the light at the detector, I, is compared with the reference light intensity, I_o, to give the transmittance, $T = I/I_o$. Transmittance can be converted to opacity, $Op = 1-T$, or optical density, $D = \log(1/T)$. The loss of light intensity can be correlated to particulate mass concentration measured by manual gravimetric sampling. In general, the measurement sensitivity of transmissometers is not fine enough to detect small changes in PM concentration. For example, in a 2 meter diameter stack (4 m path length) the smallest emission standard that should be measured with a transmissometer is 15 mg/m^3 (personal communication with Dr. Wolfgang Jockel, TÜV Rheinland, email dated March 20, 2000).

The basic operational principle of these instruments is that a collimated beam of visible light is directed through a gas stream toward receiving optics. The receiving optics measure the decrease in light intensity, and the instrument electronics convert the signal to an instrument output. An instrument incorporating the components described in the previous sentences would be considered a single pass system. For better resolution and higher accuracy, a dual-pass transmissometer and a modulating light source are used. The dual-pass transmissometer (with a reflector mirror on the opposite side of the stack from the light source) allows all of the instrument electronics to be incorporated into one unit. A high frequency modulation of the light source limits the possibility of interference because the instrument only reads the loss of light while the light source is on. When an LED light source is used, electronic modulation of the light (instead of chopping) is possible. Incorporating the light source and detector into one instrument also allows direct measurement of the loss of light by comparison of the source intensity and the loss of light at the same time. This helps prevent inaccurate readings due to the degradation of the light source intensity (a common problem in basic transmissometers).

A transmissometer used as a PM CEMS should use a red or near infrared light source, and not the white light source used on traditional opacity monitors (see Section 2.2, the discussion of Uthe's work, for an explanation). Some manufacturers have started using a green LED to monitor both opacity and PM concentration simultaneously. Furthermore, the opacity monitor's correlation to PM concentration as measured by the Reference Method should be done versus opacity or optical density.

3.5 OPTICAL SCINTILLATION

Optical scintillation, like light extinction, utilizes a light source and a remote receiver that measures the amount of received light. The difference is that the scintillation monitor uses a wide beam of light, no focusing lenses, and the receiver measures the modulation of the light frequency due to the movement of particles through the light beam and not the extinction of light. The principles at work here are that the particles in a gas stream will momentarily interrupt the light beam and cause a variation in the amplitude of the light received (scintillation). The greater the particle concentration in the gas stream the greater the variation in the amplitude of the light signal received. The scintillation monitor must be calibrated to manual gravimentic measurements at the specific source on which it is installed.

4.0 SUMMARY OF KNOWN PM CEMS

Based on the analytical measurement principles presented in Section 3.0, instrument manufacturers have developed monitors to continuously measure PM concentrations in source emissions. Most of these monitors measure a property of the particulate matter in the stack (e.g., scatter of light, transfer of charge, or modulation of transmitted light) and the concentration is then inferred based on a correlation to manual gravimetric samples. In contrast, the beta attenuation monitors produce results on a concentration basis from the mass of particulate matter collected on a filter divided by the volume of gas sampled through the filter.

This section presents a summary of most of the monitors that are commercially available from manufacturers as "off-the-shelf" PM CEMS, as listed below. Mention of specific manufacturers equipment is not an endorsement of the product by the EPA. These descriptions are solely for informational purposes.

4.1 Durag F904K Beta Attenuation
4.2 Environment S.A. 5M Beta Attenuation
4.3 Mechanical Systems Inc BetaGuard PM Beta Attenuation
4.4 Sigrist KTNR and CTNR Extractive Light Scatter
4.5 Durag DR-300-40 In-situ Light Scatter
4.6 Environmental Systems Corporation P5 In-situ Light Scatter
4.7 Sick Inc. RM210 In-situ Light Scatter
4.8 Sick Inc. FW 100 and FWE 200 Light Scatter
4.9 Grimm Technologies 6300 In-situ Light Scatter
4.10 Monitor Labs 300L In-situ Light Scatter
4.11 BHA Group CPM 5000 Scintillation
4.12 PCME Scintilla SC600 Scintillation
4.13 Insitec TESS In-situ or Extractive Laser Light Extinction-Scatter
4.14 PCME DustAlert 90 Electrostatic Induction
4.15 Auburn International Triboguard III or II In-situ Triboelectric
4.16 Codel StakGard Triboelectric Dust Monitor
4.17 Opacity/Transmissometers

Many of these PM CEMSs have been in use for 10 or more years while others are relatively new. Source specific applicability of each of these PM CEMSs is presented in Section 7.0, PM CEMS Implementation.

4.1 DURAG F904K BETA ATTENUATION

The F904K extracts a sample from the stack, transports the sample to the instrument through a heated line, and deposits PM on a filter tape during user-selected sampling periods (e.g., 4 to 8 minutes). Before and after each sampling period, the filter tape is moved between a carbon 14 beta particle source and Geiger-Mueller detector. The amount (in units of mg) of PM on the filter is determined by the reduction in transmission of beta particles between the readings for the dirty tape and the clean tape. This instrument measures the sample gas volume on a dry basis, and therefore outputs PM concentration in units of mg/dscm. The F904K samples isokinetically at normal stack gas velocity, but isokinetic sampling is not actively maintained (i.e., when the stack gas velocity decreases, the F904K's sampling rate remains constant creating a superisokinetic sampling condition and a low bias to the measured PM concentration). To minimize particulate loss in the sampling system, the F904K introduces dilution air after the sampling nozzle and samples at a high rate of about 3,000 liters per hour (~ 1.75 cfm); however, this sampling rate can be modified as needed for site-specific conditions. The measuring range is determined by the length of the sampling period, but the instrument can only accommodate up to 6 mg to 8 mg of particulate deposited on the filter tape during each sampling period. If too much particulate is collected during a sampling interval, a high vacuum is created, and the sampling is curtailed. This instrument does automatic zero and upscale drift checks to meet daily QC check requirements.

The distance between the probe and instrument is recommended to be less than 20 feet. The footprint of the F904K is approximately 30 inches by 48 inches with clearance needed in front and behind the case to open the doors. The instrument weighs about 400 pounds. A single, 6-inch port is needed for the probe installation into the stack. This instrument also requires a supply of high-pressure air and 230V of electrical power.

The F904 version was approved by the German TÜV in 1990 for all sources. The F904 version was evaluated by the EPA/OSW at the long-term field test at the DuPont Experimental Field Station liquid waste incinerator and by Eli Lilly (only during phase II) at a liquid waste incinerator. The F904K was evaluated by the EPA/OAQPS at a coal-fired boiler and by the Department of Energy at the radionuclide incinerator at Oak Ridge National Lab. The instrument is relatively insensitive to changes in the PM composition and PM properties and is not affected by the presence of condensed water droplets in the gas stream. Although the instrument output is in units of mg/dscm, a correlation to manual gravimetric data is recommended to account for any particulate stratification at the sampling point.

4.2 ENVIRONMENT S.A. 5M BETA ATTENUATION

The Beta 5M extracts a sample from the stack through a heated probe and deposits PM on a filter tape during user defined sampling periods (e.g., 4 to 8 minutes). The instrument mounts onto the end of the probe and thus does not have a sampling line. At the end of each sampling period, the filter tape is moved between a carbon 14 beta particle source and a detector. The amount (in units of mg) of PM on the filter is determined by the decrease in beta particles passing through the dirty tape as compared to the clean tape. This instrument measures the sampled volume on a wet basis, and therefore, outputs PM concentration in units of mg/acm. Since the sampled volume is measured on a wet basis, the instrument is susceptible to clogging in the volume measurement lines when used in high-stack-gas-moisture environments. The Beta 5M maintains isokinetic sampling with real-time ΔP and temperature measurements. Before the analysis is done at the end of each sampling period, the probe nozzle is closed, opened, and closed again creating a vacuum to re-entrain any PM deposited in the probe. The measuring range is determined by the length of the sampling period, but the instrument does have a lower detection limit. Currently, this instrument does not do automatic zero and upscale drift checks, but the manufacturer is reportedly developing this capability.

The footprint of the Beta 5M is a box attached to the probe with dimensions of approximately 15 inches by 30 inches by 30 inches that hangs from a support frame attached to the stack. The instrument weighs about 180 pounds. A single, 6-inch port is needed for the probe installation into the stack. This instrument also requires a supply of high-pressure air and either 115V or 230V of electrical power.

The Beta 5M was evaluated by the EPA/OSW at the long-term field test at the DuPont Experimental Field Station liquid waste incinerator, by Eli Lilly at a liquid waste incinerator, and by the Department of Energy at the radionuclide incinerator at Oak Ridge National Lab. The instrument is relatively insensitive to changes in the PM composition and properties and is not affected by the presence of condensed water droplets in the gas stream, except for the potential of clogging the sample volume lines. Although the instrument output is in units of mg/acm, a correlation to manual gravimetric data is recommended to account for any particulate stratification at the sampling point.

4.3 MECHANICAL SYSTEMS INC. BETAGUARD PM BETA ATTENUATION

The BetaGuard PM extracts a sample from the stack, transports the sample to the instrument through a heated line, and deposits PM on a filter tape during user-selected sampling periods (e.g., 4 to 8 minutes). Before and after each sampling period, the filter tape is moved between a carbon 14 beta particle source and Geiger-Mueller detector. This instrument uses a dual beta source-detector arrangement to minimize lost sample time (i.e., sampling is occurring on a second "spot" while a measurement is being made on the first "spot"). The amount (in units of mg) of PM on the filter is determined by the reduction in transmission of beta particles between the readings for the dirty tape and the clean tape. This instrument measures the sample gas volume on both a wet and dry basis, and therefore outputs PM concentration in a variety of units. The BetaGuard PM actively samples isokinetically by receiving a stack gas flow rate signal from a flow monitor. Isokinetic sampling is maintained by holding the total sample flow rate constant and then varying the amount of dilution air that is added to the sample gas. The measuring range is determined by the length of the sampling period and the selected nozzle size. The instrument can measure in a range from 1 to 500 mg/dscm. If too much particulate is collected during a sampling interval, a high vacuum is created, but, instead of aborting the sampling cycle, the amount of PM is measured and a new sampling cycle is started. This instrument does automatic zero and upscale drift checks to meet daily QC check requirements. Additionally, this instrument automatically does daily sample flow rate checks.

The distance between the probe and instrument is recommended to be less than 50 feet. The footprint of the BetaGuard PM is approximately 12 inches by 30 inches with clearance needed in front of the case to open the door. The instrument weighs about 350 pounds. A single, 6-inch port is needed for the probe installation in most stacks. This instrument also requires a supply of high-pressure air and 120V of electrical power.

The BetaGuard PM has undergone field trials done by the vendor and is being evaluated in a second Electric Power Research Institute (EPRI) field evaluation at a coal-fired boiler. The instrument is relatively insensitive to changes in the PM composition and PM properties and is not affected by the presence of condensed water droplets in the gas stream. Although the instrument vendor asserts that a site specific correlation to manual gravimetric data is not needed for a representative sample location, the EPA requires a PS-11 correlation test to account for any particulate stratification at the sampling point.

4.4 SIGRIST KTNR AND CTNR EXTRACTIVE LIGHT SCATTER

The KTNR and CTNR (newer version) are both PM CEMSs that use the principle of forward light scattering at 15° in the visible to near infrared light spectrum. The measuring ranges are from 0 to 0.1 mg/dscm up to 0 to 1000 mg/dscm. These instruments extract a heated slipstream (1 m^3/min) from a single point in the stack and pass a small portion (35 lpm) through a photometer. The extracted gas is then returned to the stack. The extraction sample rate is over-isokinetic at normal stack gas flow rate. The vendor notes that over-isokinetic sampling significantly reduces the error caused by velocity fluctuations and is an alternative to continuous monitoring of the stack gas velocity and adjustment of the sampling rate. The KTNR and CTNR do not perform automatic zero and upscale drift checks, but manual drift checks can be done on the CTNR.

The minimum space requirement for this instrument is a height of 8.5 feet, width of 5 feet, and a depth of 3.5 feet. For outdoor installations, a shelter must be provided. Two 4-inch ports are needed for the extraction and return probes. The electrical power requirement is 3-phase 400V and 230V. A transformer is offered to facilities that do not have the required power.

Both instruments were approved by the German TÜV for all source categories. The KTNR was evaluated by the EPA/OSW at the long-term field test at the DuPont Experimental Field Station liquid waste incinerator, and the CTNR was evaluated by Eli Lilly at a liquid waste incinerator and by the Department of Energy at the radionuclide incinerator at Oak Ridge National Lab. The instrument response can be correlated in mg/acm by comparison to manual gravimetric data. This instrument is sensitive to changes in particle characteristics (e.g., size, shape, and color), but because it heats the extracted sample gas to vaporize condensed water, it is not affected by the presence of condensed water droplets in the gas stream.

4.5 DURAG DR-300-40 IN-SITU LIGHT SCATTER

The DR-300-40 PM CEMS uses the principle of side light scattering at 120° in the visible light spectrum. This instrument's measuring ranges are from 0 to 1 mg/m^3 up to 0 to 100 mg/m^3, depending on the size of the aperture installed. It is therefore recommended for measurements of low PM concentrations. The "sampled volume" (i.e., the volume of stack gas where the scatter of light due to particles is detected) is located in an area 3 to 11 inches (centered at 6 inches) from the instrument's face. The DR-300-40 does automatic zero and upscale drift checks to meet daily QC check requirements.

The footprint of the DR-300-40 is a protective covering box attached to the stack with dimensions of approximately 36 inches high by 24 inches wide by 30 inches deep. A separate purge air blower and filter are needed near the instrument. The instrument weighs about 60 pounds, and the protective covering weighs about 15 pounds. A single, 5-inch by 12-inch port with a supplied mating flange is needed for installation of this instrument onto the stack. If this instrument is installed in a stack or duct less than 5 feet in diameter, an anti-reflective device (light trap) should be installed in the opposite wall in line with the incident light. The electrical power requirement is 110V.

This instrument was approved by the German TÜV in 1992 for all source categories. It was evaluated by the EPA/OSW at the long-term field test at the DuPont Experimental Field Station liquid waste incinerator and by the EPA/OAQPS at a coal-fired boiler. The instrument response can be correlated in mg/acm by comparison to manual gravimetric data. This instrument is sensitive to changes in particle characteristics (e.g., size, shape, and color) and presence of condensed water droplets in the gas stream.

4.6 ENVIRONMENTAL SYSTEMS CORPORATION P5 IN-SITU LIGHT SCATTER

The P5 uses the principle of backward light scattering at 175° in the near infrared light spectrum. This instrument's measuring range is 0.5 mg/acm up to 20,000 mg/acm. The measuring volume is located 4.75 inches from the physical end of the probe that contains both the transmitting and receiving optics. The P5 does automatic zero and upscale drift checks to meet daily QC check requirements.

The footprint of the P5 is a box attached to the port flange with dimensions of approximately 18 inches high by 12 inches wide by 36 inches deep. Also, additional clearance beyond the physical depth is needed for the drive rod (the same length as the probe). With a 3-foot probe, the instrument weighs about 160 pounds. A single, 4-inch port with flange is needed for installation of this instrument onto the stack. If the opposite wall of the stack is less than 48 inches away from the end of the probe, an anti-reflective device (light trap) should be installed in the opposite wall. The electrical power requirement is 110V.

This instrument was approved by the Korean Ministry of the Environment (non-technical evaluation) for use as a source PM monitor. This instrument was evaluated by the EPA/OSW at the long-term field test at the DuPont Experimental Field Station liquid waste incinerator and by the EPA/OAQPS at a coal-fired boiler. It is also part of a second EPRI field evaluation at a coal-fired boiler. The prototype to this instrument was evaluated at a secondary lead smelter by the University of Windsor in 1976-1977. The instrument response can be correlated in mg/acm by comparison to manual gravimetric data. Since this instrument measures in the near infrared, it is less sensitive to changes in particle size, and it has a roughly constant response to particles in the 0.1 to 10 µm range. The P5 will measure condensed water droplets in the gas stream as particulate.

4.7 SICK INC. RM210 IN-SITU LIGHT SCATTER

The RM210 uses the principle of side light scattering at 90° in the visible light spectrum. This instrument is ideally suited for measuring extremely low PM concentrations in the range of 0.0001 mg/acm up to 200 mg/acm. This instrument is available in the following three versions depending on the needed penetration of the sampled volume:

- Version 1, the sampled volume is 0.5 to 7 inches from the instrument's face,
- Version 2, the sampled volume is 6.7 to 27.5 inches from the instrument's face, and
- Version 3, the sampled volume is 13.4 to 63.8 inches from the instrument's face.

The RM210 does automatic zero and upscale drift checks using light attenuators. This instrument is essentially the same size and shape as the Durag DR-300-40.

This instrument was approved by the German TÜV for all source categories, and it was evaluated by the EPA/OSW at an early, short-term field test. The instrument response can be correlated in mg/acm by comparison to manual gravimetric data. This instrument is sensitive to changes in particle characteristics (e.g., size, shape, and color) and the presence of condensed water droplets in the gas stream.

4.8 SICK INC. FW 100 IN-SITU AND FWE 200 EXTRACTIVE LIGHT SCATTER

The Sick FW 100 and FWE 200 are new, state-of-the-art PM CEMS that use the principle of forward light scattering at 15° using a red laser light source. The FW 100 measures particulate concentrations in-situ with a 31.5-inch probe. The FWE 200 extracts stack gas using an eductor at over-isokinetic conditions, heats the sample gas in a thermal cyclone, then guides the sample gas to the measurement cell where the PM concentration is measured with the FW 100 probe. The sample gas is then deposited back into the stack. These instruments have two measuring ranges: 0 to 5 mg/acm and 0 to 200 mg/acm with a resolution of 0.1 mg/acm.

The footprint for the FWE 200 is two boxes (a measurement and control cell and a blower unit) with dimensions of approximately 33 inches high by 30 inches wide by 16 inches deep and 22 inches high by 22 inches wide by 11 inches deep. For outdoor installations, a cover is needed for the blower unit. The measurement and control cell weighs about 150 pounds and the blower weighs about 30 pounds. One 4-inch port is needed for the probe. The electrical power requirement is 115 or 230V.

The FWE 200 is being evaluated by TÜV for type certification. The instrument response can be correlated in mg/acm by comparison to manual gravimetric data. This instrument is sensitive to changes in particle characteristics (e.g., size, shape, and color), but because it heats the extracted sample gas to vaporize condensed water, it is not affected by the presence of condensed water droplets in the gas stream.

4.9 GRIMM TECHNOLOGIES 6300 IN-SITU LIGHT SCATTER

The Model 6300 uses the principle of backward light scattering in the red light spectrum (660 nm). An electronically modulated laser-diode is the light source. Since this instrument uses a laser-light, a light trap must be installed on the opposite side of the stack to prevent backscattering from reflection of the light on the opposite wall. This instrument's measuring range is 0 to 1 mg/dscm up to 0 to 10,000 mg/dscm. The instrument contains both the transmitting and receiving optics within a single box. The Model 6300 does not do automatic zero and upscale drift checks to meet daily QC check requirements, these must be done manually.

The footprint of the Model 6300 is a box with dimensions of approximately 8 inches by 6 inches by 10 inches attached to a 3-inch port flange. The instrument assembly weighs about 30 pounds. The electrical power requirement is 110V.

This instrument was tested and approved by the German TÜV at a waste incineration source in accordance with the 17th BImSchV in the 0 to 20 mg/dscm measuring range. The instrument response must be correlated by comparison to manual gravimetric data. The manufacturer asserts that water droplets are widely ignored by the instrument, due to the specially selected laser wavelength.

4.10 MONITOR LABS 300L IN-SITU LIGHT SCATTER

The 300L uses the principle of backward light scattering in the red light spectrum. An electronic modulated laser emitting diode provides the light source. The laser light is directed into the stack at a slight angle, so that, for stacks larger than about 6 feet, a light trap is not needed. This instrument's measuring range is 0 to 20 mg/acm up to 20,000 mg/acm. Manual zero and upscale drift checks can be done to meet daily QC check requirements.

The footprint of the 300L is a single optical head assembly attached to a special port flange (provided by the vendor) with dimensions of approximately 15 inches long by 8 inches high by 36 inches wide and weighing about 34 pounds. A single, 3.5 to 6-inch port with the special flange is needed for installation of this instrument onto the stack. A purge air system (about 17 inches wide by 8 inches deep by 37 inches high and weighing about 71 pounds) is needed to keep the optical surface clean. The electrical power requirement is 120V.

The instrument response must be correlated in mg/acm by comparison to manual gravimetric data. The 300L will measure condensed water droplets in the gas stream as particulate.

4.11 BHA GROUP CPM 5000 SCINTILLATION

The CPM 5000 uses the principle of scintillation or modulation in the intensity of the transmitted light beam. The receiver senses the light signal modulation and converts it to PM concentration (i.e., signal modulation is proportional to PM concentration). The transmitter and receiver are located on opposite sides of the duct; therefore, this instrument measures across stack PM concentration. As the PM concentration increases, the amplitude of the signal modulation increases, and the instrument response can be correlated in mg/acm by comparison to manual gravimetric data. Because the CPM 5000 measures signal variations resulting from moving particles rather than from a diminished intensity of the incident light beam, the instrument is relatively unaffected by particulate accumulation on the optics windows, optical misalignment, or aging of the transmitter and receiver. The CPM 5000 has zero and upscale drift check capabilities for daily QC checks.

The footprint of the CPM 5000 is a box containing the microprocessor controls with dimensions of approximately 24 inches square and 6 inches deep. The transmitting and receiving optical heads are small and are attached to 2.5-inch port flanges on opposite sides of the stack. The microprocessor control box weighs about 30 pounds and the optical heads each weigh about 3 pounds. Two 2.5-inch ports are needed for installation of this instrument onto the stack. The electrical power requirement is 110V.

This instrument was tested as part of the short-term field test done by EPRI at a coal-fired boiler, and it is also being evaluated in a second EPRI field test. The CPM 5000 was approved by the German TÜV to meet the requirements for accuracy and repeatability for power plant applications. The CPM 5000 will measure condensed water droplets in the gas stream as particulate.

4.12 PCME SCINTILLA SC600 SCINTILLATION

The Scintilla SC600 uses optical scintillation technology coupled with advanced design techniques to monitor PM concentration. The SC600 can measure PM concentration as low as 2.5 mg/acm per meter of path length. The scintillation technology and advanced techniques reduce zero and upscale drift. The instrument uses modulated light to eliminate effects of stray or ambient light. The transmitter and receiver are located on opposite sides of the duct; therefore, this instrument also measures across-stack PM concentration. The instrument response increases with PM concentration and can be correlated in mg/acm by comparison to manual gravimetric data. The SC600 has zero and upscale drift check capabilities for daily QC checks.

The footprint of the SC600 is a small control module with dimensions of approximately 10 inches wide by 7 inches high by 4 inches deep. The transmitting and receiving optical heads are small and are attached to 2-inch port flanges on opposite sides of the stack. The control module weighs about 8 pounds and the optical heads each weigh about 12 pounds. Two 2-inch ports are needed for installation of this instrument onto the stack. The electrical power requirement is 110V.

This instrument was tested as part of the short-term field test done by the EPRI at a coal-fired boiler, and it is also part of a second EPRI field evaluation at another coal-fired boiler. The SC600 has MCERTS approval meeting the accuracy and repeatability requirements for power plant applications. The SC600 will measure condensed water droplets in the gas stream as particulate.

4.13 INSITEC TESS IN-SITU OR EXTRACTIVE LASER LIGHT EXTINCTION-SCATTER

The Insitec TESS provides real-time PM concentration data for particles ranging in size from 0 to 20 microns. The TESS can measure PM concentrations in-situ with an up to 8-foot-long probe or in a sample extracted from the stack. The in-situ TESS has been evaluated in both laboratory and field studies by the Department of Energy (DOE), Southern Research Institute, and the EPA (Giel et al., 1995). The in-situ TESS is capable of measuring PM concentration as low as 1.3 mg/acm. A prototype of the extractive TESS was demonstrated in a short-term field test done by EPRI at a coal-fired boiler. The manufacturer indicates the instrument is insensitive to particle variations (particle size distribution) and to process changes (particle composition).

4.14 PCME DUSTALERT 90 ELECTROSTATIC INDUCTION

The DustAlert 90 uses a patented electrostatic induction measurement principle; where particles in the gas stream interact with a probe inserted in the duct and induce charge movement in the probe. The AC current generated by charge induction in the probe can be directly related to the PM concentration. This instrument filters out the DC current generated by the particulate/probe interaction. The manufacturer asserts that the DustAlert 90 can measure PM concentration as low as 0.02 mg/acm. Unlike triboelectric technology, the particles do not need to collide with the probe to be detected. The instrument's output can be correlated to mg/acm from manual gravimetric data. However, it is more often used to display and record in a relative "Emission Factor" scale, which indicates emissions as a multiple of "reference" emissions (i.e., as a baghouse bag leak detection device). The DustAlert 90's correlation to PM concentration is affected by changes in particle size distribution, particle type, and particle charge, thus eliminating applications on wet exhaust gas stacks and sources controlled by electrostatic precipitators.

The footprint of the DustAlert 90 is a small module with dimensions of approximately 10 inches wide by 7 inches high by 4 inches deep. The module extends about 6.5 inches back from the port. A 7/8-inch diameter sensor probe extends into the stack and is attached by a 1.5-inch NPT port. The electrical power requirement is 110V.

This instrument has been type certified by the Environment Agency under the MCERTS program in the United Kingdom. Also, TÜV notes that this instrument should only be used in constant velocity and constant gas composition environments; however, the velocity restriction does not apply to the DustAlert 60 model.

4.15 AUBURN INTERNATIONAL TRIBOGUARD III OR II IN-SITU TRIBOELECTRIC

The Triboguard II and III use proven triboelectric technology, invented nearly 25 years ago. These instruments are low maintenance and can detect baseline PM concentrations as low as 0.005 mg/acm (as established by the manufacturer). The Triboguard instruments are primarily used for baghouse broken bag detection (Fabric Filter Bag Leak Detection Guidance, 1997). Since triboelectric type instruments are sensitive to changes in stack gas velocity, particle size, and particle characteristics (e.g., charge and composition), the Triboguard instruments are not commercially marketed as potential PM CEMS; however, they are used in some applications in the United Kingdom. This instrument is roughly the same size as the DustAlert 90.

4.16 CODEL STAKGARD TRIBOELECTRIC DUST MONITOR

The StakGard uses triboelectric technology (i.e., the AC current generated by particles flowing around the probe) to detect PM concentration. The AC current generated by charge induction in the probe can be directly related to the PM concentration. This instrument filters out the DC current generated by the particulate/probe interaction. The manufacturer asserts that the StakGard can measure PM concentration as low as 0.1 mg/acm. The instrument’s output can be correlated to mg/acm from manual gravimetric data; however, it is more often used as a baghouse bag leak detection device. The StakGard’s correlation to PM concentration is affected by changes in particle size distribution, particle type, and particle charge; however, Codel has designed a metal mesh housing around the probe to reduce the effect of particle charge after an ESP. This instrument has been type certified by the Environment Agency under the MCERTS program in the United Kingdom. This instrument is also roughly the same size as the DustAlert 90.

4.17 OPACITY/TRANSMISSOMETERS

For completeness, and because some opacity monitors have been type certified as particulate CEMSs, opacity monitors have been included in this section on known PM CEMSs. Although each opacity monitor is not presented separately as the other PM CEMS presentations above, Table 4-1 includes a comparison on many opacity monitors that could be applicable as a PM CEMS in specific applications.

TABLE 4-1. COMPARISON OF OPACITY MONITORS AS PM CEMSs

	Land Combustion 4500 mkII	Durag DR-280	Durag DR-290	KVB-Enertec MIP	Monitor Labs - USI 560 LightHawk	Rosemount OPM 2000R	Sick OMD 41	Phoenix Instruments OPAC 20/20
Dual Pass	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
Light Source	LED - Green	Tungstun Lamp - White	Wide Band Diode-White	Helium-Neon Laser - Green	LED - Green	Frosted, incandescent lamp - White	LED - Yellow	LED - Green
Electrical/ Mechanical Modulation	Electrical 3k Hz	Mechanical 1.2k Hz	Electrical 2kHz	Electrical	Electrical 2.4k Hz	Liquid crystal windows (electrical)	Electrical	Electrical 2.5k Hz
PM Measurement Concentration	As low as 1.5 mg/acm (1 μm dust)	From 0-0.1 to 0-1.6 extinction	1 mg/acm resolution for 1 μm dust and 10-foot path length		For 1 μm dust and 20-foot path length - single-digit mg/acm	From 0 to 3 extinction	From 0-0.1 to 0-2 extinction; PM concentration as low as 1.2 mg/acm	From 0-0.1 to 0-2 extinction
Footprint	30" long x 18" wide x 24" high including purge system and shutters	Transceiver 7" wide x 9" high x 22" deep Retroreflector 7" x 9" x 13"	Transceiver 7" wide x 13" high x 16" deep Retroreflector 7" x 10" x 11"	Transmitter 12" wide x 18" high x 6" deep Receiver 5" x 5" x 8" without purge system	22" long x 20" wide x 33" high including purge system and weather cover	34" long x 13" wide x 29" high including purge system	Transceiver 15" x 8" x 11" Reflector 11" x 8" x 11" without purge system and protective cover	Both sides 22" wide x 30" high Transceiver 27" long Retroreflector 18" long Includes weather cover and air purge system with shutters

TABLE 4-1. (CONTINUED)

	Land Combustion 4500 mkII	Durag DR-280	Durag DR-290	KVB-Enertec MIP	Monitor Labs - USI 560 LightHawk	Rosemount OPM 2000R	Sick OMD 41	Phoenix Instruments OPAC 20/20
Weight	60 lb per side	Transceiver 35 lb Retroreflector 13 lb Purge air blowers 65 lb each	Transceiver 22 lb Retroflector 15 lb Purge air with weather hood 65 lb each side		Transceiver 27 lb Retroreflector 7 lb Purge air blower 22 lb Weather cover and mounting plate 43 lb	Transceiver 80 lb Retroreflector 40 lb	Transceiver 27 lb Retroreflector 18 lb	Transceiver 26 lb Retroreflector 9 lb Weather enclosure and air purge system 125 lb/side
Electrical Power Requirement	110 V	115 V 220 V for blowers	90-264 V 48-62 Hz	110 V 110 V for blowers	115 V 220 V for blowers	110-240 V	90 … 267 V 120 V/3 or 230 V/3 for purge air system	115 V or 220 V
Type Approval	German TÜV - 1997	German TÜV - 1978	German TÜV - 2000 expected				German TÜV - 1995	

5.0 SUMMARY OF PM CEMS DEMONSTRATION FIELD STUDIES

Many field studies demonstrating the performance of PM CEMSs have been conducted. TÜV conducted most of the early evaluations and type certifications of PM CEMSs. Later, as the EPA considered their use, the EPA performed several field evaluations of PM CEMSs. Also, at least two industry groups have done field evaluations of PM CEMSs. This section presents a summary of those field studies.

5.1 TÜV CERTIFICATION TESTING OF PM CEMS

In Germany, all CEMSs, including PM CEMSs, are type certified and approved for use at a particular industry type. A PM CEMS cannot be used on a source in Germany unless it has been certified. TÜV is the principle agency that conducts CEMS certifications in Germany.

5.1.1 Sigrist CTNR

The Sigrist CTNR, a light scattering type PM CEMS, was evaluated by TÜV Rheinland in the laboratory and in the field (Report on the Suitability Testing . . . CTNR, 1997). The laboratory test checked the following using two identical instruments:

- All instrument functions,
- Instrument characteristics (linearity and common response),
- Stability of the zero and reference filter values,
- Effect of variations in supply line voltage,
- Effect of relative humidity, rain, vibrations, and operating position, and
- Proper operation of the self-monitoring feature.

The field test was done using the same two instruments from the laboratory test at a refuse incinerator from April 16, 1997 to June 4, 1997 and at a coal-fired furnace from June 12, 1997 to August 12, 1997. The field test evaluated the following:

- Dead time and setting time,
- Detection limit,
- Correlation capability,
- Reproducibility,
- Stability of instrument characteristics,
- Maintenance interval,

- Data availability, and
- Functional test and correlation.

The results of TÜV's evaluation of the Sigrist CTNR PM CEMS indicate that it met all of the applicable requirements with the exception that it does not have the capability of doing automatic zero and upscale calibration checks. However, TÜV recommended the CTNR for monitoring PM emissions from incinerators and power plants, noting the reservation about the lack of an automatic calibration feature.

5.1.2 Durag F-904

The Durag F-904, a beta gauge type PM CEMS, was evaluated by TÜV Rheinland in the laboratory and in the field (Performance Testing of the F-904 Beta Gauge). The laboratory test checked the following:

- Effect of variations in supply line voltage, and
- Effect of changes in ambient temperature on (1) the zero and span signals, (2) the total volumetric flow sampled during the measuring cycle, and (3) the dilution air volume.

The field test was done on two identical instruments at a municipal waste combustor from July 31, 1989 to December 31, 1989. The instruments were installed downstream of an ESP and wet scrubber and operated in the following stack gas conditions:

• Stack diameter	78.7 inches
• Average stack gas velocity	45.9 feet per second
• Dew point of stack gas	149°F
• Stack gas temperature	154.4°F
• PM concentration	< 10 mg/acm

The TÜV report notes that the F-904 was tested under recognizably difficult operating conditions. The field test evaluated the following monitor features:

- Correlation capability,
- Reproducibility,
- Maintenance interval, and
- Data availability.

The results of TÜV's evaluation of the Durag F-904 PM CEMS indicate that it met all of the applicable requirements with the exception of the sample volume audit. On two of 13 tests, the sample volume deviated from the expected volume by more than the allowable 8 percent. However, this test was done at a dilution ratio of 4 to 1, and TÜV determined that the monitor could fully meet the sample volume accuracy requirement at a dilution ratio of 2 to 1.

5.1.3 Durag DR-300-40

The Durag DR-300-40, a light scatter type PM CEMS, was evaluated by TÜV Rheinland in the laboratory and in the field (Report on the Performance Testing of the D-R 300-40 Dust Concentration Monitor, 1992). The laboratory test checked the following:

- Calibration capability in a test duct, where the effect of changes in particulate size was evaluated,
- Effect of variations in supply line voltage,
- Effect of changes in ambient temperature,
- Testing of the dirty window correction,
- Linearity check, and
- Effect of ambient light.

The field test was done on two identical instruments at a secondary lead smelter kiln from February 27, 1992 to June 3, 1992. The instruments were installed downstream of a baghouse and operated in the following stack gas conditions:

• Stack diameter	41 inches
• Stack gas velocity	30 to 59 feet per second
• Dew point of stack gas	50 to 122°F
• Stack gas temperature	140 to 230°F

The field test evaluated the following monitor features:

- Correlation capability and effect of process changes on the correlation stability,
- Reproducibility,
- Maintenance interval ,
- Data availability, and
- Necessity of a light trap.

The results of TÜV's evaluation of the Durag DR-300-40 PM CEMS indicate that it met all of the applicable requirements with the following notes:

- For installations on thick or double-walled stacks, the scattering volume must be within the flowing stack gas.
- Since the scattering volume is only 3 to 11 inches from the instrument face, for installations on stacks greater than 6.5 feet in diameter, the monitor must be shown to provide a representative sample.
- A light trap may be omitted if the interference from reflected light is demonstrated to be less than 2 percent of the measuring range.

5.2 EPA/OSW FIELD DEMONSTRATION – HAZARDOUS WASTE INCINERATORS

The OSW wanted to propose PM CEMSs as part of their Hazardous Waste Combustion MACT rule. Before proposing PM CEMSs, OSW did two preliminary field studies and a comprehensive field evaluation.

5.2.1 Mixed Solid and Liquid Hazardous Waste Incinerator

The first preliminary test examined three PM CEMSs at a mixed solid and liquid hazardous waste incinerator located in Bridgeport, New Jersey. The three PM CEMSs were chosen to represent three different measurement techniques: light scattering, time-dependent optical attenuation, and beta attenuation. The CEMSs were installed downstream of a pilot scale wet electrostatic precipitator (ESP). The focus of this test was to determine the PM CEMS's viability at a wet ESP installation.

The test was conducted in three phases during March of 1995. First, the PM CEMSs were calibrated according to ISO 10155 using EPA Method 5. Three paired Method 5 tests were done at each of three operating conditions designed to produce different PM loadings. The PM concentrations ranged from a low of about 1 mg/m^3 to a high of about 30 mg/m^3. Second, the CEMSs were operated for 2 weeks. Finally, another set of Method 5 tests were done to check the stability of the original calibration. The final Method 5 testing consisted of four paired test runs at only two operating conditions. PM concentrations were less than 1 mg/m^3 during all four test runs (i.e., the change in operating conditions did not change the PM concentration).

The PM CEMSs evaluated were the following:

- Sick Inc. RM200,
- BHA Group CPM1000$^{\text{TM}}$, and
- Environment S.A. Beta M5.

The Sick RM200 and BHA CPM1000 were operating for the initial Method 5 tests, during the 2-week experimental period, and the final Method 5 tests. The Beta M5 was not operating during the initial Method 5 tests but operated during the experimental period and final Method 5 tests.

The OSW reported the following conclusions from this brief test:

- The calibration data did not meet ISO 10155 requirements for (1) three or more different PM concentration levels and (2) nine or more data points.
- With proper care, an optical device used in conjunction with a heated bypass can be calibrated in a wet exhaust stream.
- For a low-temperature, saturated stack gas stream, extracting and drying a slipstream is more appropriate than attempting to make in-situ optical measurements. The CPM1000 responded to liquid droplets in the exhaust stream.
- Not enough data were obtained to properly evaluate the performance of the Beta M5.
- The PM CEMSs responded to changes in PM concentration levels.

More information on this test can be found in the document entitled "Draft Technical Support Document for HWC MACT Standards, Volume IV: Compliance with the Proposed MACT Standards," February 1996, Pages 4-2 to 4-9.

5.2.2 Hazardous Waste Burning Cement Kiln

The OSW chose a hazardous waste cement kiln in Fredonia, Kansas for another evaluation of PM CEMSs and a test of the initial draft PM CEMS performance specification (PS-11) criteria. The facility manufactures cement from raw materials in a two-phase wet process kiln. Particulate emissions are controlled with an ESP. The PM CEMSs selected included two light-scattering monitors: the ESC P5A and the Sick RM200. The tests involved triplicate testing at three different ESP power settings ranging from 55 to 140 KW; each Method 5 test run had paired trains. Initial Method 5 correlation tests were done in May and June 1995. A final test was done in July 1995 and served as a simulated response correlation audit (RCA). The test contractor had extreme difficulty obtaining consistent results between the paired Method 5 trains. A concerted effort was made to achieve an appropriate test matrix and distribution over three PM levels for each calibration test. During each test period, data from one of the Method 5 trains was disregarded as suspect.

The OSW reported the following conclusions from this brief test:

- The correlation is highly sensitive to errors that can occur in making the manual method measurements.
- The ESC P5A correlation test produced encouraging but inadequate results in terms of meeting the draft PS-11 criteria. Also, the P5A's RCA test results did not meet the performance criteria.
- The Sick RM200 experienced some operational problems attributed to the heated, purge-air system. The instrument was removed during the initial correlation test program. When the instrument was reinstalled, the response continued to deteriorate.

More information on these tests can be found in the document entitled "DRAFT Particulate Matter CEMS Demonstration, Volume I: DuPont, Inc. Experimental Station On-site Incinerator," Wilmington, DE, December 1997, Pages 2-42 to 2-44.

5.2.3 DuPont Hazardous Waste Incinerator

The preliminary tests presented above encouraged OSW to conduct a long term (6 months to 9 months) demonstration to determine what PM CEMS performance could be achieved at a reasonable worst-case source. Because the work would be used to support a proposed requirement that a PM CEMS be used on a hazardous waste combustion device, OSW chose the DuPont Experimental Station's hazardous waste incinerator for this demonstration. Among such sources, a source like DuPont's would cause the particulate matter in the stack to be more variable, thus causing a more variable response from the PM CEMS than at other sources under consideration (e.g., cement kilns and light-weight aggregate kilns). The EPA also obtained information to characterize PM CEMS installation needs, data availability, maintenance and personnel requirements, and costs. One particularly important piece of information learned from this test was that the PM CEMS can be sensitive to emissions variability on a real-time basis. Neither periodic short-term manual testing nor operational parametric monitoring would provide an adequate picture of this variability for standard setting purposes. Only PM CEMS data collected over a relatively long period of time would provide data sufficient for the statistical analyses necessary for establishing achievable continuous compliance emissions limits.

In addition to the importance of long term data gathering in setting standards, the EPA also learned from this test the importance of precise manual particulate matter measurements. The variability associated with manual method imprecision can mask the true performance of the PM CEMS. In response to this issue and to improve sample recovery and analysis time, the EPA chose to redesign the Method 5 equipment when used at low particulate concentration sources. These changes became EPA's Method 5i. To evaluate method precision, the EPA used dual Method 5i trains (two Method 5i trains conducted simultaneously from different ports) and established acceptable paired train precision criteria.

The EPA also learned much about PM CEMS performance characteristics. This information included the need to address the performance characteristics of different technologies, the need to use data flags as indicators of potential problems, the importance of instrument set-up and a "debugging period." This knowledge led to changes in the draft performance specification criteria and associated QA/QC requirements.

The DuPont tests extended over a 9-month period, from September 1996 to May 1997. Tests conducted from September to November, 1996 were an extension of the learning experience started in the EPA's preliminary test program. Data collected from September to November 1996 were not considered in the final analysis of results. Forty-four Method 5i paired train tests were conducted from December 1996 through May 1997. The EPA conducted the initial correlation testing in 1-week periods each month from December 1996 through March 1997. A second correlation was done in April 1997. Finally, the 9-month demonstration program ended with a RCA in May 1997.

In summary, these tests led the EPA to believe that PM CEMS are a viable accurate measure of real-time particulate matter emissions. The EPA believes the approach to correlating emissions to gravimetric manual methods can result in an adequate correlation. The EPA also believes that data availability, maintenance and personnel, and overall costs associated with particulate matter CEMSs are representative of other CEMSs, such as SO_2 analyzers for utility boilers. However, site decisions, such as the technology employed for a given application, the QA/QC capabilities of the CEMS, and the accuracy of the manual method data collected, can affect the viability of a given PM CEMS at a particular source. More information on the DuPont tests can be found in the Particulate Matter CEMS Demonstration final report at the EPA Office of Solid Waste's Web site: http://www.epa.gov/epaoswer/hazwaste/combust/CEMS.

5.3 ELECTRIC POWER RESEARCH INSTITUTE – COAL-FIRED BOILER WITH ESP

Another field test program was sponsored by EPRI and conducted at Georgia Power Company's Plant Yates. Yates Unit 7 uses a conventional Combustion Engineering tangentially fired boiler with a rated generating capacity of 360 MWe. The unit burns eastern bituminous coal and is equipped with low NO_X burners and separate overfire air. The particulate emission limit for Unit 7 is 0.24 lb/mmBtu, and particulate emissions are controlled by an ESP. This program was designed to provide data for use in a rigorous evaluation of both ESP performance models and PM CEMS.

The following five devices were tested:

- BHA CPM 5000,
- PCME SC600,
- Insitec extractive TESS,
- Spectrum Systems (via Sabata), and
- Lear Seigler RM41 opacity monitor.

Of the four instruments classified as a PM CEMS, only the BHA CPM 5000 and PCME SC600 were commercially available at the time of the EPRI test, and only the BHA CPM 5000 had been used on other field evaluations. The PCME SC600 has since received MCERTS approval. The Insitec extractive TESS and Spectrum System devices were prototypes.

The test plan was to evaluate three different ESP power conditions, which would result in three different particulate mass emission levels, during three separate weeks of testing, for a total of nine independent test conditions. Testing was done in June and September 1998. During each week, 15 paired Method 17 test runs were conducted. The first 2 weeks of testing were performed during consecutive weeks and the third week of testing was approximately 3 months later. The fundamental premise of this field evaluation was to use the initial week of testing to develop correlation equations for the PM CEMSs. The second week of testing, conducted immediately following the initial week, provided information regarding the short-term accuracy and stability of the PM CEMSs. The third week of testing, conducted approximately 3 months following the initial 2 weeks, provided information regarding the long-term accuracy and stability of the correlations. Unfortunately, during the 3-month period between the week 2 and week 3 tests, the four PM CEMSs were not properly maintained.

PM concentrations were varied by (1) deenergizing ESP fields (i.e., simulating the complete loss of ESP sections, the most common failure mode of an ESP) and (2) turning down power on all ESP sections in increments (i.e., simulating problems attributable to high-resistivity ash or close clearance). PM concentrations during the 3 weeks of testing are presented in Table 5-1.

TABLE 5-1. PM CONCENTRATIONS FOR THE THREE WEEKS OF THE EPRI PM CEMS TEST

PM concentrations	Week 1	Week 2	Week 3
Low	~ 0.002 lb/10^6 Btu, 1.8 mg/m^3 and 3 percent opacity	~ 0.012 lb/10^6 Btu, 9.1 mg/m^3 and 6.7 percent opacity	~ 0.019 lb/10^6 Btu, 15.3 mg/m^3 and 7.4 percent opacity
Mid	~ 0.06 lb/10^6 Btu, 49.5 mg/m^3 and 15 percent opacity	~ 0.057 lb/10^6 Btu, 42.3 mg/m^3 and 16.0 percent opacity	~ 0.121 lb/10^6 Btu, 94.5 mg/m^3 and 18.3 percent opacity
High	~ 0.23 lb/10^6 Btu, 174 mg/m^3 and 25 percent opacity	~ 0.121 lb/10^6 Btu, 87.5 mg/m^3 and 21.5 percent opacity	~ 0.149 lb/10^6 Btu, 119 mg/m^3 and 19.2 percent opacity

The high-PM-concentration condition during week 1 produced a significant number of "chunky" carbon particles; therefore, this condition was not repeated in the other test periods.

The conclusions from this EPRI study were the following (Roberson et al., 1999):

- The paired Method 17 sampling trains showed very good measurement precision and a tolerance interval of 12 mg/m^3 at an emission limit value of 75 mg/m^3 (~ 0.10 lb/mmBtu).
- The BHA CPM 5000, PCME SC600, and prototype Insitec extractive TESS passed the draft PS-11 correlation criteria. The prototype Spectrum and opacity monitor had confidence intervals and tolerance intervals well outside the draft PS-11 requirements. The PM CEMSs correlation statistics from the week 1 test are presented in Table 5-2.
- The week 3 tests that were used for the RCA, showed that none of the three PM CEMS that passed the initial correlation met the RCA criteria.

- The ESP inlet particle size distribution ranged from 21.5 to 24.4 microns for the first two weeks of testing and was 30.9 during the third week. EPRI believes the skewed particle size distribution and geometric standard deviation is due to either the retrofit of low-NO_X burners in a short furnace or the wearing of the coal pulverizes.

TABLE 5-2. PM CEMSs CORRELATION STATISTICS FOR THE EPRI PM CEMS TEST

Instrument	Correlation Coefficient	Confidence Interval	Tolerance Interval
BHA CPM 5000	0.986	6.7 %	18.2 %
PCME SC600	0.984	6.9 %	19.2 %
Insitec extractive TESS	0.991	9.4 %	19.2 %
Spectrum Systems (via Sabata)	0.939	21.1 %	45.5 %
Lear Seigler RM41 opacity monitor	0.937	13.6 %	41.1 %

More detailed information on the EPRI test at Plant Yates can be found in a paper written for the EPRI CEM Users Group Meeting at the following RMB Consulting Web site: http://www.rmb-consulting.com/cinnati/rlrpaper.htm

5.4 ELI LILLY – HAZARDOUS WASTE INCINERATOR

Eli Lilly and Company (Eli Lilly), the Chemical Manufacturers Association (CMA), and the Coalition for Responsible Waste Incineration (CRWI) jointly sponsored a two-phase test program of PM CEMSs. The summary presented below was taken from a draft report provided by Eli Lilly. This test was done at a liquid hazardous waste incinerator at the Eli Lilly Clinton Lab in Clinton, Indiana. The instruments assessed in this study were an Environment S.A. (ESA) Model Beta 5M and a Sigrist Photometer AG (Sigrist) Model KTNRM/SIGAR4000.

Phase one of the program demonstrated that the instruments, as initially configured, would not meet the requirements of draft PS-11. During the same period as Phase One, Eli Lilly purchased and installed two Sigrist monitors at a facility in Ireland. Eli Lilly contracted TÜV Rheinland to calibrate the instruments which led to new knowledge on the calibration of PM CEM instruments. Eli Lilly conducted Phase Two testing using knowledge gained from the Phase One testing, the DuPont testing, and the TÜV Rheinland calibration in Ireland.

5.4.1 Phase One

Phase One of the Eli Lilly evaluation was designed to duplicate the testing conducted at the DuPont Hazardous Waste Incinerator, but on a source that was saturated with water vapor. The evaluation was conducted over a 5-month period from February to June 1998. During this period, a total of 74 paired Reference Method 5i (M5i) sample runs were completed at varying particulate levels from 17 to 45 mg/dscm at 7 percent O_2. Of the 74 test runs, 70 test runs produced acceptable paired M5i results.

The Reference Method data was compared to the output of the two instruments and the requirements of draft PS-11 with the following conclusions:

- None of the data sets met the draft PS-11 criteria for correlation coefficient but most passed the CI and TI criteria.
- The Sigrist had a significantly higher correlation coefficient than the ESA monitor did.
- The "best fit" correlation relation for the ESA was polynomial, versus little difference between the linear and polynomial correlations relations for the Sigrist.
- Use of the polynomial correlation relation for the ESA would significantly limit the range of the instrument.
- Evaluation of quarterly sets of the Sigrist data showed different slopes and correlation coefficients.

The data availability of the instruments was 78 percent for the ESA and 96 percent for the Sigrist. The ESA instrument, as designed and operated, had trouble dealing with the high moisture level. Finally, both instrument's measuring range was set too wide for the range of PM concentrations.

In general, Lilly believes that the Phase One test was a learning experience, and the Phase One results should not be used to judge the performance of these PM CEMSs.

5.4.2 Phase Two

Phase Two of the Eli Lilly program was designed using lessons learned from previous testing. Phase Two incorporated new instrument operating procedures as well as design changes to the ESA instrument. Eli Lilly noted the following changes were included:

- The Sigrist instrument was limited to operate on a single range that spanned the known particulate concentration (i.e., multi-ranging capability was eliminated because of non-linearity between ranges).
- The ESA instrument had some design changes incorporated to make it operate better at the high moisture levels.
- The sample period for the ESA instrument was changed from 6 to 15 minutes, changing the sample collection time from 2.5 to 8.5 minutes.

During Phase Two (November to December 1998), 40 sets of paired train data were collected using M5i with particulate concentrations ranging from 1 to 64 mg/dscm at 7 percent O_2. Of the 39 paired test runs (after one run, train 2 failed its leak check), four failed the precision criteria. The paired train bias comparison had a correlation coefficient of 0.99 and a slope of 0.97, indicating no bias.

The Method 5i test data was compared to the output of the two instruments and the requirements of draft PS-11 with the following conclusions:

- Both instruments met the draft PS-11 correlation criteria. The correlation statistics are presented in Table 5-3.
- Successful correlation required operating the incinerator at abnormal conditions to obtain the needed range of PM concentration (i.e., the waste feed was stopped and only natural gas was combusted to produce the low PM concentrations).
- During the Phase Two test, the incinerator was operated in excess of the proposed PM standard for a hazardous waste combustor.
- Successful correlation required a substantial site-specific operational learning process with the instruments (i.e., supporting the need for the shakedown period and correlation test planning period in PS-11, see Sections 7.3 and 8.3 of this report).

Evaluation of the data collected shows that the best correlation relationship of the Sigrist monitor was logarithmic with a correlation coefficient of 0.97. The ESA monitor was found to have a linear relationship with a correlation coefficient of 0.99.

TABLE 5-3. PM CEMSs CORRELATION STATISTICS FOR THE LILLY PHASE TWO PM CEMSs TEST

Instrument	Correlation coefficient	Confidence interval	Tolerance interval
ESA Beta 5M	0.99	2.6 %	9.1 %
Sigrist KTNR	0.97	6.7 %	24.3 %

Although both instruments met the correlation criteria, Eli Lilly had concerns because the Sigrist was at the maximum tolerance level, 25 percent, of draft PS-11. Also, the ESA did not track with the Sigrist 12.3 percent of the time. The trend analysis was based on an analysis of the data using mA output of the monitor and the regression equation calculated using the data from this test. During the periods in which the two instruments did not trend together, data from the ESA were higher than the Sigrist. The difference was assumed to be in the ESA data because in several instances the ESA had a sample volume error, but this error was not recorded.

The data availability of the instruments for Phase Two were 98.1 percent for the Sigrist and 85.8 percent for the ESA. The data for the periods that the ESA did not trend with the Sigrist were treated as an instrument malfunction for the ESA.

5.5 EPA/OAQPS FIELD DEMONSTRATION – COAL-FIRED BOILER WITH BAGHOUSE

The EPA's Office of Air Quality Planning and Standards (OAQPS) may require the use of PM CEMSs in future standards. Also, States may require them for State Implementation Plan (SIP) monitoring and Economic Incentive Program (EIP) monitoring. Additionally, industry sources may use PM CEMSs for Title V monitoring. The EPA, therefore, desired additional evaluations of PM CEMS technology on a long-term continuous basis. Also, the EPA wanted additional data to support revisions to draft PS-11 and Procedure 2. The EPA initiated a demonstration program to setup and operate PM CEMSs over an extended time to gather data for assessing their performance against draft PS-11 and Procedure 2. The EPA chose a coal-fired power plant that used a baghouse for particulate control for the test site.

The test site was Cogentrix of Rocky Mount Inc., located in Battleboro, North Carolina. This facility is an electric utility plant consisting of four identical boilers powering two electric generating units. Each generating unit is rated at approximately 55-60 MWe for a total plant electrical capacity of 115 MWe. Each of the generating units is powered by a pair of Combustion Engineering stoker-grate power boilers. Each of the four boilers fires bituminous coal and is rated for 375 mmBtu/hr heat input and steam output of 250,000 lb/hr. Each is equipped with a Joy Technologies, Inc. dry type SO_2 absorber (lime slurry scrubber) and a Joy Technologies pulse-jet fabric filter (baghouse) for particulate control. The particulate emission limit for each boiler is 0.02 lb/mmBtu.

The following three commercially available PM CEMSs (two light scattering types and one beta gauge type) were included in the demonstration:

- ESC P5B,
- DURAG DR-300-40, and
- DURAG F904K.

The demonstration project proceeded as follows:

- The PM CEMSs were installed in early June 1999.
- A shakedown period lasted from June 12 through June 30, 1999.
- A 7-day drift test was done on each PM CEMS, an ACA was done on the two light scatter type PM CEMSs, and a sample volume audit (SVA) was done on the beta gauge type PM CEMS.
- A correlation test planning period consisting of nine preliminary Method 17 runs, which were used for assessing the range of emissions (i.e., how to obtain three levels of PM concentration) and setting the measurement range on the PM CEMS, was carried out over the period of July 9-14, 1999.
- The initial correlation test consisting of 15 paired Method 17 runs was carried out during the period of July 15-19, 1999.
- An RCA and ACA/SVA were done in late August 1999, about 1 month after the initial correlation test.
- A second RCA and ACA/SVA were done in November 1999 to evaluate discrepancies between the initial correlation and the first RCA.
- A final ACA/SVA was done on February 7, 2000 with project completion on February 16, 2000.

The duration of the demonstration project was approximately 8 months, with continuous operation of the PM CEMSs and emissions data collection over the 6-month period following the initial correlation test. All PM CEMSs were maintained in proper operating order during the demonstration with daily zero and upscale drift evaluations.

PM concentrations were varied by adjusting a multi-position butterfly valve to bypass PM from the inlet duct (dirty side) to the outlet duct (clean side) of the baghouse. The PM concentrations during the initial correlation test and the RCAs are presented in Table 5-4.

TABLE 5-4. PM CONCENTRATIONS FOR THE EPA/OAQPS PM CEMS TEST[a]

PM concentrations	Initial correlation	First RCA	Second RCA
Low	~ 4.5 mg/dscm and 3.7 percent opacity	~ 3.6 mg/dscm and 5.1 percent opacity	No tests done at low PM conc.
Mid	~ 16.4 mg/dscm and 4.1 percent opacity	~ 18.6 mg/dscm and 4.7 percent opacity	~ 22.5 mg/dscm and 9.3 percent opacity
High	~ 24.4 mg/dscm and 4.7 percent opacity	~ 38.6 mg/dscm and 5.5 percent opacity	~ 38.2 mg/dscm and 9.6 percent opacity

[a] Opacity readings were taken in the stack which discharges emissions from both boilers 2A and 2B.

Conclusions from this EPA/OAQPS demonstration were the following (Evaluation of Particulate Matter Continuous Emission Monitoring Systems, 2000):

- The 37 paired Method 17 sampling trains during the initial correlation and the first RCA showed very good measurement precision with an RSD of no greater than 4.3 percent. The bias between Trains A and B was only 2 percent for the initial correlation test and 2.3 percent for the first RCA. Except for one test run to demonstrate precision, paired trains were not used during the second RCA.
- Three levels of PM concentrations could be obtained for a baghouse controlled unit by using a baghouse bypass system that simulated a typical baghouse failure. When using a particulate bypass system to increase the PM concentration, the point where the dirty gas mixes with the clean gas must be well upstream of the manual reference method and the PM CEMS measurement locations to avoid possible stratification of the PM.
- All three PM CEMSs passed the draft PS-11 initial correlation criteria at an emission limit of 17 mg/acm (used for the light scattering instruments) or 25.5 mg/dscm (used for the beta gauge instrument) using a linear regression relation. The correlation statistics are

presented in Table 5-5. Note, the DR-300-40 had a confidence interval of 10.4 percent compared to a criteria limit of 10 percent.

- All three PM CEMSs passed the initial QC checks for the 7-day drift, ACA, and SVA.
- All three PM CEMSs failed to meet the RCA criteria after 1 month of operation. Based on results from the second RCA, a likely cause in the discrepance between the initial correlation data and the first RCA data was a shift in the PM stratification at the PM CEMS measurement location (which did not meet PS-11 siting criteria).
- Correlations generated using the combined initial correlation data and the RCA data failed to meet the draft PS-11 criteria, and the correlations generated using only the RCA data were just outside the draft PS-11 criteria bounds. During the second RCA, data collected during 5 of the 6 test runs done at full boiler operating load fell within the tolerance interval of the first RCA correlations.
- At reduced and variable boiler load conditions, the three PM CEMSs did not respond to the higher PM concentrations as expected.
- The two light scatter type PM CEMSs met the ACA criteria after 1 month, 4 months, and 6 months of operation.
- The beta gauge PM CEMS met the SVA criteria after 1 month, 4 months, and 6 months of operation.
- Assuming that plant personnel could have responded to the observed maintenance issues in a reasonable time, the light scatter PM CEMSs achieved 99 percent data availability and the beta gauge PM CEMS achieved over 96 percent data availability.

TABLE 5-5. PM CEMSs CORRELATION STATISTICS FOR THE OAQPS PM CEMSs FIELD EVALUATION

Instrument	Correlation coefficient	Confidence interval	Tolerance interval
ESC P5B	0.964	9.20 %	17.9 %
DURAG DR-300-40	0.955	10.4 %	20.2 %
DURAG F904K	0.988	5.37 %	10.7 %

6.0 FUTURE FIELD DEMONSTRATIONS

The EPA anticipates that additional field demonstrations of PM CEMSs will be done by both the EPA and industry. To facilitate a successful field demonstration, this section presents some guidelines that should be considered.

6.1 TEST PLAN GUIDELINES

A field demonstration or evaluation of PM CEMSs should be done in accordance with a written test plan. In general, a written test plan should follow the outline provided in the Emission Measurement Center's 1991 Guidebook: "Preparation and Review of Site Specific Test Plans." The site specific test plan (SSTP) should contain the following information:

1. Introduction
   - Summarize the test program and what criteria will be used to evaluate the PM CEMS(s)
   - Show a test program organization
2. Source Description
   - Describe the process that is generating PM emissions
   - Describe the control equipment
3. Test Program
   - Describe the test objectives (e.g., demonstrate that a PM CEMS provides reliable and accurate data for this source over an extended period, evaluate maintenance requirements, determine if a PM CEMS satisfies PS-11 and Procedure 2 criteria)
   - Show the test matrix, including personnel responsibilities (e.g., site modifications, shakedown and planning periods, initial correlation test period, Procedure 2 audits, instrument maintenance)
   - Describe how the source and control equipment will be operated and how PM concentrations at different levels will be obtained
4. Sampling Locations
   - Include a diagram or photograph of the Reference Method sampling location
   - Include a diagram or photograph of the PM CEMS measurement location,
5. Sampling and Analytical Procedures

- Describe the PM CEMS(s), including what instrument data will be logged (e.g., daily calibration drift, operational flags, data averaging periods)
- Describe the Reference Method used, including dual/paired train arrangement, and how on-site results will be obtained (as applicable)
- Present what process operating data will be collected to evaluate operation of the source and control equipment

6. QA/QC Activities
   - Present QC procedures that will be applied to the Reference Method sampling
   - Present QC procedures that will be applied to the PM CEMS (e.g., daily calibration drift checks, ACA, SVA) and who will do them
   - Describe how the PM CEMS(s) measurement range will be properly set
   - Conduct an independent check of the regression analysis
7. Safety Issues

6.2 MONITOR SELECTION GUIDELINES

When selecting a PM CEMS for a field demonstration project, the following should be considered:

- What technology is to be demonstrated?
- Is that technology known to be affected by site specific conditions (see Section 8.2)? If no, then the technology can be considered; if yes, then only consider the technology if precautions are taken to offset the effect.
- Considering the measurement location, can the potential PM CEMS be installed (i.e., consider platform size and location versus the size of the instrument, stack/duct diameter, weight limitations, installation efforts, exposure effects, the need for a light trap, etc.)?
- Select a PM CEMS that is commercially available. If a prototype PM CEMS is to be evaluated, a second PM CEMS that uses the same technology and has been proven should also be used.
- Only use a PM CEMS that does zero and upscale drift checks and one that has operational fault indicators.
- Ensure the vendor can provide adequate support and assistance.

6.3 TEST PLAN APPROVAL AND DATA ANALYSIS

The final test plan should be completed at least 45 days before the initial correlation testing is planned. For a field demonstration sponsored by the EPA, the industry group affected should be given the opportunity to review the test plan. The industry group can provide comments to the EPA. The industry group will also be invited to witness the initial correlation testing and any other part of the program they desire. For a field demonstration sponsored by an industry, the industry should submit the final test plan to the EPA and State agency for review at least 45 days before the initial correlation testing. In reciprocation, the EPA and the State agency should be invited to witness the initial correlation testing and any other part of the program they desire.

Results of the field demonstration should be shared between the industry group and the EPA. The industry group and the EPA are encouraged to separately analyze the data. Finally, a consensus should be reached regarding the conclusions of the demonstration.

7.0 PM CEMS IMPLEMENTATION

Once PS-11 is finalized and published in the Federal Register, the EPA, State regulatory agencies, and industry will be tasked with implementing PM CEMS programs. This section provides guidance on the following topics: source applicability, how to select the appropriate PM CEMS, how to conduct the initial correlation, what does the correlation mean and how accurate are the data generated by the PM CEMS, what QA/QC measures to apply to PM CEMS, and finally, issues to be addressed case by case.

7.1 SOURCE APPLICABILITY

PM CEMSs have three main applications: (1) process monitoring, (2) compliance assurance, and (3) compliance monitoring. As a process monitor, a PM CEMS can be used to improve process performance by providing an indication that a setpoint has changed and an adjustment is needed or to improve air pollution control device performance by indicating when maintenance is needed. As a compliance assurance monitor, a PM CEMS can be used as an indicator for reasonable assurance that an emission limit is not exceeded. A small amount of testing would be needed to establish the not-to-exceed level, but a full correlation test can be avoided. As a compliance monitor, the PM CEMS would provide a continuous record of actual PM concentration. To be used as a compliance monitor, a full correlation test is needed. Specific source applications of the PM CEMS in each of these areas are presented below.

The ESC P5B light scatter PM CEMS has been used as an ESP performance monitor at many large electric utility plants in the U.S. (personal communication with Robert Nuspliger, ESC). Furthermore, a PM CEMS has been used to monitor for product losses through an exhaust stack during process changes (e.g., in the exhaust duct of a potato chip manufacturing process to monitor for oil losses during process changes).

In Canada, many PM CEMSs are in use at pulp and paper mills with some being used as environmental compliance assurance monitors in lieu of more frequent Reference Method testing for compliance. In the United Kingdom, PM CEMSs are used at municipal waste combustors, power plants, and cement kilns in a compliance assurance manner (personal site visits at two facilities and personal communication with the U.K. Environment Agency, September 1999). Also, in Korea, PM CEMSs are used in a compliance assurance manner.

PM CEMS have been applied in Germany to industrial furnaces (i.e., coal- and oil-fired units larger than 50 MW and gas-fired units greater than100 MW) following the requirements of the 13th BlmSchV and to waste incinerators following the requirements of the 17th BlmSchV. In Denmark, PM CEMSs are used at coal-fired power plants. In the United States, PM CEMSs have been installed and evaluated on liquid hazardous waste burning sources, cement kilns, copper smelters, a glass furnace, and oil- and coal-fired boilers.

When a PM CEMS is used for compliance monitoring, the PM emission limit that is used as a compliance set point should be based on PM CEMS data collected from many representative sources over an extended period (e.g., at least 6 months). The accuracy limitations of a PM CEMS must also be considered when setting an emission limit. For example, in Germany the PM CEMS's confidence interval (e.g., 4 mg/dscm) is added to the baseline PM emission standard (e.g., 30 mg/dscm) to determine the facility's daily emission limit (e.g., 34 mg/dscm). Also, the averaging period and whether the average is a block or rolling average are critical choices to be made. These choices will have an effect on sources ability to remain in compliance (Joklik, 1999). Furthermore, the definition of particulate itself can be problematic at some sources, especially when comparing in-situ PM CEMS measurements to extractive Reference Method measurements (i.e., because of condensible particulate).

7.2 PM CEMS SELECTION

Since a PM CEMS determines PM concentration by measuring secondary properties of the particulate, selecting the appropriate PM CEMS technology for the source is a critical first step. Site-specific conditions must be considered (see Section 6.2 of this report). Also, different types of PM CEMSs can report different PM concentrations for the same sample stream just because of the concentration units (i.e., mg/dscm versus mg/acm) used in the correlation test. Some of the factors that affect PM concentration measurements made by the PM CEMSs presented in Section 4 of this report are offered below (Joklik, 1999) along with some practical suggestions.

- Opacity and light scattering monitors have responses that are functions of the particulate's index of refraction and size distribution. However, in addition to being more sensitive than opacity monitors, light scatter monitors also provide more degrees of design freedom. Parameters such as light wavelength, scattering angle, and solid angle of detection affect the response of the instrument, which makes it possible to minimize the influence of index of refraction and size distribution over certain specified size ranges. However, since optical techniques effectively measure particle volume, using them to infer PM concentrations introduces an additional dependence on particle density. Since these instruments respond to liquid droplets in the sample gas stream, in-situ devices of this type are inappropriate for saturated or nearly saturated exhaust streams. Extractive devices of this type that heat the sample gas may be used on saturated or nearly saturated exhaust streams. Additionally, using these types of instruments on sample gas streams that are likely to have varying particle size distributions is less desirable, unless precautions are taken to avoid the effects of changing particle sizes (e.g., multiple correlation curves). These instruments are most appropriate for sources controlled by fabric filters (i.e., baghouse) or multi-stage air pollution control systems in which the particle size distribution at the outlet of the device does not vary much.

- Beta gauge monitors have a weak dependence on particle composition. This effect arises because of the composition dependence of the electron mass-attenuation coefficient (the atomic number versus atomic mass ratio). The main issues associated with the use of a beta gauge PM CEMS are practical ones: maintaining isokinetic sampling may be necessary and sample loss may occur in the probe. The importance of these issues will be site dependent. Since beta gauge type instruments are much less sensitive to changes in particle size than optical based instruments, these instruments are more appropriate for sample gas streams that are likely to have varying particle size distributions (e.g., following an ESP or sources that use many different fuels). Also, since beta gauge type instruments extract and heat the sample gas, these instruments are appropriate for sample gas streams that are saturated or nearly saturated. If a beta gauge instrument is used at a source that varies its exhaust gas stream velocity a great deal (e.g., load following electric power plant), the instrument must have the capability to adjust its sampling rate to maintain isokinetic sampling.
- The response of probe electrification devices is a function of resistivity of the particles, which depends on particle composition and humidity. The response is also affected by flow velocity, particle size, and particle charge. Also, since a physical probe is inserted

into the sample gas stream, effects due to erosion and deposition must be considered. A PM CEMS of this type should only be used in exhaust streams that do not have varying particle sizes, do not have varying velocity, do not have saturated or near saturated conditions, and do not have varying particle charge (e.g., cement kiln controlled by a fabric filter). Probe electrification devices based on the AC portion of the current are not as sensitive to gas velocity changes as DC measuring devices.

- The PM CEMS measurement location is critical, especially if the PM concentration will be artificially increased for purposes of developing the correlation relation. The point where high-PM-concentration gas is mixed with low-PM-concentration gas must be well upstream of both the PM CEMS and the manual Reference Method measurement location. This is to ensure the particulate is evenly distributed and well mixed across the stack area at the measurement location. Also, devices that can introduce dilution air or otherwise disturb the air flow pattern must be well upstream of the PM CEMS measurement location.

7.3 SITE-SPECIFIC CORRELATION TEST

Since a PM CEMS measures secondary properties of particulate (with the possible exception of the beta gauge type monitors) and outputs a signal that is proportional to the PM concentration, a PM CEMS must be correlated to the site specific conditions at the measurement location. Also, a site-specific correlation will account for any PM stratification that may exist at the PM CEMS measurement location. The procedure for carrying out a correlation test is described in PS-11. Some specific issues related to the correlation test are presented in this section. A correlation test consists of the following steps:

1. Install an appropriate PM CEMS at a representative location and start it according to the manufacturer's instructions.

2. Operate the PM CEMS and record the output for a Shakedown Period and then a Correlation Test Planning Period (up to a 6-month period may be needed). Establish a proper measurement range at the end of the Correlation Test Planning Period. The Shakedown Period and Correlation Test Planning Period must not extend beyond the date when the PM CEMS must be used to report emissions.

3. Carefully, conduct 15 paired train Reference Method tests for particulate while simultaneously collecting PM CEMS output values over the range of PM CEMS responses recorded during the Correlation Test Planning Period. Higher PM CEMS responses may be tested to increase the effective range of the correlation equation by perturbing the air pollution control system or other means.

4. Evaluate the Reference Method data for precision and bias, and calculate the statistically appropriate correlation equation (linear or polynomial) from the valid, concurrent PM CEMS responses and Reference Method PM concentrations.

5. For the selected correlation equation, compare the statistical parameters to the PS-11 criteria.

The main issues to resolve during the Shakedown Period and Correlation Test Planning Period are the following:

- Plant people must learn how to properly operate the PM CEMS.
- The process should operate over its full operating envelope, especially in the areas that are suspected to affect PM composition and concentration (e.g., all expected waste feeds, all fuels, start-up and shutdown, sootblowing).
- The proper measuring range or sensitivity level must be set such that normal operations are approximately 6 to 10 mA output but that concentrations at and just above the emission limit do not exceed the upper measurement point (i.e., 20 mA). Also, the measuring range must never be exceeded for a 15-minute average period. Completing this task will likely require some Reference Method testing before the initial correlation test.
- The operating conditions that produce low and high PM concentrations must be documented so that those conditions can be reproduced for the correlation test. If changes in operation cannot produce a range of PM concentrations, some technique of perturbing or bypassing the pollution control system can be used.

During the initial correlation test, the most critical task is to carefully and properly perform the manual Reference Method tests and laboratory analysis. This task is critical because the accuracy of the PM CEMS correlation can be no better than the accuracy of the Reference Method measurements. The sole reason for requiring dual sampling trains is to help ensure the accuracy of the Reference Method values by checking that the precision between the paired

Reference Method results is sufficiently high and that the bias between the two sampling systems is sufficiently low. Although having a high level of precision between paired numbers does not guarantee that either number is accurate, the chance that the number is accurate is greater than with a single value. Another important point is to coordinate starting and stopping of the test runs with the sampling interval of the PM CEMS. This point is most important for a batch type, extractive PM CEMS (i.e., a beta gauge). Also, if port changes during the Reference Method tests take a long time (e.g., 5 minutes or more), the PM CEMS data during port changes can be discarded from the PM CEMS's average output.

Since the paired Reference Method results must be evaluated for their precision before the run can be considered valid, getting PM concentration results in the field is highly recommended. This requires sample recovery and laboratory analysis in the field. Furthermore, checking the progress of the test program by plotting the Reference Method values against the PM CEMS's output during the correlation test is highly recommended.

Another requirement for a valid correlation test per draft PS-11 is to collect PM concentrations over the full range of PM CEMS responses recorded during the Correlation Test Planning Period. At most sources, some effort (e.g., operational changes or adjustments to the pollution control system) will be needed to obtain the full range of PM concentration levels. Testing at PM concentrations above the emission limit is not required. Some examples of how a source might obtain lower and higher PM concentrations are the following:

- For low PM concentrations:
    - Burn only natural gas
    - Stop product feed
    - Shut off process and only run the fans
    - Use filtered sample air
- For high PM concentrations:
    - Change fuels combusted
    - Change product or waste feed
    - Perturb or bypass the pollution control system to simulate normal, unpreventable upsets

The EPA is aware that some sources will not be able to create a wide range of PM concentration levels for the correlation test. Therefore, draft PS-11 allows a source to perform the correlation test over the range of PM concentrations normally experienced. The PM CEMS is then limited to how far its response can be used for reporting PM emissions (i.e., 125 percent of the highest PM CEMS response during the correlation test) before additional data must be collected to extend the correlation. For example, if the PM CEMS responses ranged from 4.5 mA to 5 mA during the correlation testing, the corresponding correlation equation from this data could be used up to a PM CEMS response of 6.25 mA. When three hourly averages exceed 6.25 mA, additional test data at PM CEMS responses around 6.25 mA would have to be added to the correlation data. This approach is particularly appealing when the limited range of PM concentrations is much lower than the standard. This approach is used in Germany.

7.4 UNDERSTANDING THE MEANING OF THE CORRELATION

After a successful correlation test and development of the correlation relation equation, one must understand the meaning and appropriate use of the regression equation (Joklik, 1999). The estimated regression equation that correlates the manual gravimetric PM concentration measurements (e.g., mg/dscm) and PM CEMS measurements (e.g., mA) has associated with it a degree of uncertainty expressed by two hyperbolae around the fitted line of the regression equation (i.e., the mean of the estimated PM concentration values.) The first is a confidence interval, defined in PS-11 as a 95 percent confidence level. The second is a tolerance interval, defined in PS-11 as a 95 percent tolerance interval that contains at least 75 percent of the entire population of PM concentration values. In other words, a tolerance interval will bracket at least a certain proportion (e.g., 75 percent) of the population with a specified degree of confidence (e.g., 95 percent). The width of the band determined by these bounds is narrowest at the point defined by the mean of PM CEMS measurements and mean of PM concentration measurements. The farther one moves away from the mean, the wider the bounds become. Thus, extrapolating the estimated regression line and its confidence and/or tolerance bounds will necessarily result in decreased precision in PM concentration measurements estimates. Therefore, the EPA's policy decision to limit the amount of extrapolation of a regression equation developed from data over a narrow range of PM CEMS responses to 125 percent of the largest PM CEMS response is supported by the statistical meaning of the correlation.

For a given PM concentration (i.e., mg/acm), several different PM CEMS responses (i.e., mA signal) can occur within the bounds of the tolerance interval (following along a horizontal line from the upper tolerance interval to the lower tolerance interval, this is based on inverse regression). Conversely, for a given PM CEMS output, several different PM concentrations can occur (following along a vertical line from the lower tolerance interval to the upper tolerance interval). Thus, the uncertainty in the PM concentration reported by a PM CEMS's correlation relation equation that meets PS-11 acceptance criteria is limited to ± 25 percent of the emission limit value.

7.5 QUALITY ASSURANCE/QUALITY CONTROL

Quality assurance (QA) has two functions in the PM CEMS program:

1. Assessment of the continued quality of the PM CEMS's data, and
2. Maintaining data quality by implementing quality control (QC) policies and corrective action.

When the assessment function indicates a reduction in data quality, the QC procedures must be revised until the PM CEMS produces data of acceptable quality. The specific QA/QC activities found in Procedure 2 for a PM CEMS program are the following:

- Quality check of Reference Method data,
- Daily zero and upscale drift checks,
- Daily sample volume check (where applicable),
- Relative response audit (RRA),
- Response correlation audit (RCA),
- Absolute correlation audit (ACA), and
- Sample volume audit (SVA), where applicable.

As noted earlier, collecting quality manual Reference Method data is key to a successful PM CEMS program. The quality of the Reference Method data applies to the initial correlation test described earlier and to the RCA test. The quality of the Reference Method data is first evaluated by the population relative standard deviation (RSD) between the paired Reference Method data points from each individual test run. The RSD must meet the following criteria:

IF	THEN
the average PM concentration > 10 mg/dscm	RSD < 10 percent
the average PM concentration < 1 mg/dscm	RSD < 25 percent
the average PM concentration is between 1 and 10 mg/dscm	RSD < the percentage determined from the following equation: -(15/9) * mg/dscm + 26.667 (i.e., the linear interpolation between 25 percent at 1 mg/dscm and 10 percent at 10 mg/dscm)

If the pair of Reference Method PM concentration values meets the RSD criteria, the data are deemed acceptable. At the conclusion of the test program (either initial correlation or RCA), all valid pairs are evaluated for systematic bias. The bias is evaluated by calculating the linear regression of all valid pairs (Train B versus Train A), and comparing the slope from the linear regression to the range of 0.93 to 1.07. If the slope is between 0.93 and 1.07, the bias is acceptable, and the averages of each paired train are used in the initial correlation relation or RCA.

On a daily basis, the PM CEMS is subjected to zero and upscale drift checks. This routine check is done to assess system electronics and optics, light and radiation sources and detectors, electric or electro-mechanical systems, and general stability of the system calibration. Basically, the zero and upscale drift check is a daily health check of the instrument (i.e., is it still responding to a reference value today as it did yesterday and the day before that, etc?). In general, the instrument must be adjusted when the daily drift exceeds 4 percent, but it may be adjusted at lower drift values. The instrument is considered out-of-control (i.e., the data are not valid for compliance determination) when either the zero or upscale drift exceeds 4 percent for 5 consecutive days or exceeds 8 percent on any one day.

For extractive type PM CEMS that measures the sample volume and uses the measured sample volume as part of calculating the output value, a check of the sample volume measuring equipment must be done on a daily basis. This sample volume check is done at the normal sampling rate of the PM CEMS. The PM CEMS sample volume measurement must be adjusted whenever the daily sample volume check exceeds 10 percent. The instrument is considered out-of-control (i.e., the data are not valid for compliance determination) when the sample volume check exceeds 10 percent for 5 consecutive days or exceeds 20 percent on any one day.

At least once each calendar quarter (but no closer than 2 months), the PM CEMS must have an ACA and a SVA (as applicable) done. The ACA applies to all types of PM CEMSs, and the SVA applies to extractive type PM CEMSs that use the measured sample volume to calculate PM concentration. An ACA and a SVA are higher level performance checks than the daily checks. The ACA is designed to evaluate the performance of the PM CEMS across its full measuring range by checking the instrument's response at three audit points. If any of the ACA audit points have an error in excess of ± 10 percent of the audit value, the instrument must be repaired and a new audit done to confirm the proper operation of the instrument. The PM CEMS manufacturer should provide the source with materials for the audit. A SVA is done by measuring the instrument's sample volume with a calibrated device (e.g., dry gas meter) and comparing the audit value to the volume reported by the instrument. If the SVA shows an error in excess of ± 5 percent of the audit value, the instrument must be repaired and a new SVA done to confirm the proper operation of the instrument. Procedure 2 provides the method for performing the SVA.

At the frequency specified in the regulation that requires the PM CEMS, at least 12 paired manual Reference Method tests for the RCA must be conducted following the same procedures described for the initial correlation test. Each paired train result must meet the same RSD criteria as for the initial correlation. The RCA must include PM concentrations within the range obtained during the initial correlation test. For the RCA, at least 9 of the 12 sets of PM CEMS/Reference Method measurements must fall within the initial correlation's tolerance interval bounds. If the PM CEMS fails to meet this RCA criteria, the PM CEMS is out-of-control, and the following two actions must be taken:

1. Combine the RCA data with the initial correlation data and perform the regression analysis in PS-11 to develop a new correlation relationship. If this new correlation meets the PS-11 criteria, the new correlation must be used, or

2. Do the PS-11 regression analysis on the new RCA data. If this new correlation relation meets PS-11 criteria, it must be used.

Once every four calendar quarters, a RRA must be conducted. The RRA consists of collecting three simultaneous Reference Method PM concentration measurements and PM CEMS measurements at the as-found source operating conditions and PM concentration. Paired trains for the Reference Method sampling are not required but are recommended to avoid failing the test due to imprecise and inaccurate Reference Method results. For the RRA, at least 2 out of the 3 test runs must fall within the tolerance interval to ensure the PM CEMS correlation is still applicable and accurate. EPA believes the RRA is a cost effective means to ensure that the PM CEMS correlation remains applicable without the need to complete a costly RCA on an annual basis. If the PM CEMS fails to meet this RRA criteria, the PM CEMS is out-of-control, and a full RCA must be completed.

7.6 PS-11 ISSUES TO BE ADDRESSED CASE BY CASE

As discussed previously, the EPA produced a draft performance specification (PS-11) to govern the installation and calibration of a PM CEMS. The EPA has been revising PS-11 based on the results of its and industry's field evaluations of PM CEMSs and comments received to the proposed PS-11. Many issues have been resolved, but several issues need to be resolved on a case by case basis. The PS-11 case by case issues are the following:

1. How to vary the source's PM emission concentrations during the correlation test.
    - How to simulate a normal, unpreventable, expected failure of the APCD?
    - If adjusting the APCD changes the characteristics of the PM in the stack, some types of PM CEMSs will not be applicable.
    - What effect does fuel changes have on the PM concentration?
    - Can sootblowing be used to increase the PM concentration?
    - Can and should the product feed be stopped to get near zero emissions?
    - Is testing during start-up and shut-down viable?
    - Can clean sample gas be used for a zero point?
    - Is the zero point hypothesis (i.e., 0 mg/m^3 = 4mA) valid? The zero point hypothesis is used by the German agency, and the tests done by Eli Lilly while only combusting natural gas support the zero point hypothesis concept.
2. Can and should multiple correlations be used in some instances when clearly the PM characteristics change?

3. For sources having condensible materials in the exhaust stream, the PM CEMS must be able to measure PM at the Reference Method filter temperature. If condensible PM is included in the total particulate, in-situ PM CEMS (e.g., light scattering, probe electrification, light extinction, and optical scintillation) may not be applicable.

In addition to PS-11, the EPA also produced QA and QC measures designed to ensure that the ongoing PM data collected by the PM CEMS is valid. These QA/QC measures are found in Procedure 2. The following QA/QC and data handling issues must be specified in the applicable regulation:

1. What is the appropriate frequency for confirming the correlation (e.g., annually, every 18 months, every 5 years)? In Germany, many correlations are not checked for 5 years. The EPA added a 3-run Reference Method check of the correlation equation, called a relative response audit, to be done annually.
2. What is continuous data (e.g., are four 15-minute block averages needed for an hourly average), and how does continuous apply to batch type monitors (i.e., beta attenuation)? If a batch type PM CEMS samples stack gas for 9 minutes out of each 15-minute period, is this CEMS collecting continuous data?

8.0 SUMMARY OF PS-11 AND PROCEDURE 2

The initial proposed versions of PS-11 and Procedure 2 were published in the Draft Technical Support Document for HWC MACT Standards, Volume IV: Compliance with the Proposed MACT Standards dated February 1996. Public comment was received, and additional revisions were made. PS-11 and Procedure 2 were published again in December 1997. Additional comments were received, and EPA has continued to learn about the capabilities and performance of PM CEMS. The following sections present EPA's latest approach to PS-11 and Procedure 2. EPA intends to publish a supplemental proposal for PS-11 and Procedure 2 by the end of 2000.

8.1 PS-11

PS-11 is used for evaluating the acceptability of a PM CEMS at the time of or soon after installation, and whenever specified in the source's applicable regulation. This performance specification requires site-specific correlation of the PM CEMS response against manual gravimetric Reference Method measurements (including those made using EPA Reference Methods 5 or 17). PS-11 outlines the procedures and acceptance criteria for installation, operation, calculations, and reporting of data generated during a PM CEMS correlation. PS-11 is unique, relative to the performance specifications for other CEMS because it is based on a technique of correlating PM CEMS response to emissions determined by the Reference Method. This differs from a CEMS measuring gaseous pollutants which has available calibration gases of known concentration.

As presented in Section 4 "Summary of Known PM CEMS," several different types of PM CEMSs, which use different operating principles, are available. The selection of an appropriate PM CEMS is dependent on site-specific configurations, flue gas conditions, and PM characteristics (see Section 7 "PM CEMS Implementation" for source applicability). After an appropriate PM CEMS is selected, it must be installed at an accessible location downstream of all pollution control equipment. The PM CEMS concentration measurements must be performed from a location considered most representative or from one that can provide data that can be corrected to be representative of the total PM emissions as determined by the manual Reference Method. The site-specific correlation developed during the Performance Specification testing must relate specific PM CEMS responses to integrated particulate loadings.

After completing the initial field installation, the PM CEMS is operated for a Shakedown Period. The objective of the Shakedown Period is for the facility operators to become familiar with the PM CEMS and its routine operation for providing reliable data. The Shakedown Period continues until the instrument technicians are comfortable with the operating characteristics of the PM CEMS and that the PM CEMS is operating within the manufacturer's specifications. After completing the Shakedown Period, the PM CEMS is operated for a Correlation Test Planning Period. The objective of this period is to identify the full range of operating conditions and PM emissions to be used in the PM CEMS correlation test. During the Correlation Test Planning Period the process and air pollution control equipment are operated in their normal set of operating conditions, except when attempts are purposely made to produce higher emissions. The Correlation Test Planning Period continues until the source owner is satisfied that the complete range of PM emissions have occurred. During the Correlation Test Planning Period, the operators must establish whether the monitor is operating in a suitable range(s) relative to the source's emission profile. The objective here is to assure that the monitor's measurement range is broad enough to measure peak emissions yet sensitive enough to address low-emission conditions. Ideally the monitor should be reading near mid-scale during normal conditions but never reading off-scale during peak emissions.

The performance of the PM CEMS is judged from the results of two tests: (1) 7-day drift test and (2) initial correlation test. The 7-day drift test is to validate the internal performance of the PM CEMS relative to its own zero and upscale drift checks for seven consecutive days. The purpose of the 7-day drift measurement is to verify that the PM CEMS response is the same as that established during the development of the initial correlation and to determine whether the PM CEMS is in control during day-to-day operation. The initial correlation test is done to develop the relationship between the PM CEMS responses and the manual Reference Method results over a range of PM concentrations. Collection of Reference Method PM data using paired trains is required. Each set of paired train results must achieve a specific level of precision to be used in the correlation data set.

For the correlation relation tests, a minimum of 15 valid runs must be conducted, each consisting of simultaneous PM CEMS and Reference Method measurements sets and covering the full range of PM concentrations identified during the Correlation Test Planning Period. The

Reference Method measurements consist of paired trains operated simultaneously. For acceptable Reference Method measurements, the paired trains must meet precision and bias criteria. Ideally, the manual Reference Method data would be distributed over the complete operating range experienced by the facility, with at least 20 percent of the minimum 15 measured data points in each of the following three levels:

- Level 1: From zero PM concentration to 50 percent of the maximum PM concentration.
- Level 2: 25 to 75 percent of the maximum PM concentration.
- Level 3: 50 to 100 percent of the maximum PM concentration.

Although the above levels overlap, individual run data may only be applied in one level. Lower and higher than normal PM concentrations may be intentionally created by operating the facility outside of its normal operation, but, at a minimum, the correlation data must include the range of PM CEMS responses observed during the Correlation Test Planning Period. The correlation relation can only be extrapolated to 125 percent of the highest PM CEMS reading observed during the correlation test. If the PM CEMS records readings higher than 125 percent of the highest PM CEMS reading observed during the correlation test for three consecutive hours, three additional Reference Method test runs must be made at the higher PM CEMS response. The correlation relation must be revised within 30 days of the occurrence.

Developing a PM CEMS correlation will affect plant operations for about a week while the correlation tests are being performed. PS-11 does not require the source to emit PM that exceeds the PM emission limit during the correlation test.

From the complete set of correlation data, the correlation coefficient, confidence interval, and tolerance interval are calculated for a polynomial and a linear regression. A test to determine if the polynomial regression offers a statistically significant improvement to the preferred linear regression is done. The correlation coefficient, confidence interval, and tolerance interval for the selected regression must meet the performance criteria in PS-11.

8.2 PROCEDURE 2

40 CFR Part 60, Appendix F, Procedure 2 describes the procedures used to evaluate the effectiveness of QA and QC procedures and the quality of the data produced by any PM CEMS that is used for compliance monitoring. The QA/QC practices of Procedure 2 consist of

- daily drift and sample volume checks
- quarterly audit of the PM CEMS's accuracy in response to reference standards
- quarterly audit of the measured sample volume
- longer-term assessment of the stability and applicability of the initial correlation relation.

Also included in Procedure 2 are assessments of the accuracy and precision of the Reference Method data used in the correlation relation assessment.

Procedure 2 requires a written QA Plan that includes complete detailed QA/QC procedures. If the PM CEMS fails to meet the acceptable criteria for any Procedure 2 audit, the PM CEMS is called out-of-control. When the PM CEMS is out-of-control for two consecutive periods, procedures in the QA Plan must be enhanced to prevent a repeat of the out-of-control condition.

9.0 PM CEMS COST

The data on Tables 9-1 and 9-2 are based on actual expenditures experienced by the EPA in field studies, information gained from interviews with users, and the expected costs of appropriate QA/QC requirements in the draft performance specifications and associated procedures. The tables point out that costs can vary widely, mainly according to the frequency of the RCA. Since the costs in Tables 8 and 9 were developed, the EPA has received new information about PM CEMS costs. The EPA believes the First Costs may be a little low because of the potential need for more Reference Method particulate testing than originally anticipated. Additional test runs may be needed during the Correlation Test Planning Period in order to assess the proper measurement range for the PM CEMS.

TABLE 9-1. IN-SITU (LIGHT SCATTERING) PM CEMS COSTS[a]

Task	Total cost $
Total First Costs (Equipment, installation, initial testing, correlation)	102,600 - 132,600
Total Annual Costs – RCA done every year	51,800 - 82,800
RCA done every 18 months	40,700 - 71,700
RCA done every 3 years	29,600 - 60,600

TABLE 9-2. EXTRACTIVE (BETA GAUGE) PM CEMS COSTS[a]

Task	Total cost $
Total First Costs (Equipment, installation, initial testing, correlation)	140,000 - 170,000
Total Annual Costs – RCA done every year	58,200 - 88,800
RCA done every 18 months	47,100 - 77,700
RCA done every 3 years	36,000 - 66,600

[a] Assumptions for these tables are given in Appendix A

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APPENDIX A

BREAKDOWN OF PM CEMS COSTS

LIGHT SCATTERING PM CEMS COSTS

Task	**Total Cost $**
Planning	3,500
Select Equipment	10,300
Provide Support Facilities	1,000 - 8,100
Purchase CEMS	36,000 - 47,100
Install & Check CEMS	9,900
Performance Spec. Tests	25,000 - 36,800
Prepare QA Plan	16,900
Total First Costs	**102,600 - 132,600**
Operation & Maintenance	12,900
Annual RATA (O_2 monitor)	0 - 5,800
PM Monitor RCA	15,000 - 26,300
Quarterly ACA	1,000 - 7,000
Record Keeping	7,500
Annual Review & Update	1,000 - 4,400
Capital Recovery	14,364 - 18,880
Total Annual Costs	**51,800 - 82,800**
If RCA done every 18 months	**40,700 - 71,700**
If RCA done every 3 years	**29,600 - 60,600**

BETA GAUGE PM CEMS COSTS

Task	Total Cost $
Planning	3,500
Select Equipment	10,300
Provide Support Facilities	1,000 - 8,100
Purchase CEMS	71,000 - 82,100
Install & Check CEMS	12,300
Performance Spec. Tests	25,000 - 36,800
Prepare QA Plan	16,900
Total First Costs	**140,000 - 170,000**
Operation & Maintenance	13,700
Annual RATA (O_2 monitor)	0 - 5,800
PM Monitor RCA	15,000 - 26,000
Quarterly ACA	1,000 - 7,000
Record Keeping	7,500
Annual Review & Update	1,000 - 4,600
Capital Recovery	20,000 - 24,200
Total Annual Costs	**58,200 - 88,800**
If RCA done every 18 months	**47,100 - 77,700**
If RCA done every 3 years	**36,000 - 66,600**

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Ms. Rhodora Woolner
U.S. Department of Justice
ENRD/LPS
P.0. Box 4390
Ben Franklin Station
Washington, D.C. 20044-4390

April 7, 2008

Re: Proposed Consent Decree of Citizen Suit Public Citizen and Sierra Club v. American Electric Power Company, Inc, and Southwest Electric Power Company; Civil Action No. 5:05-cv-00039-DF

Dear Ms. Woolner:

Plaintiffs and Defendants in the above referenced matter have reached an accord that they propose to memorialize and lodge with the court. In accordance with 40 C.F.R. 135.5, Plaintiffs are now providing the Department of Justice with a copy of the parties' proposed consent decree for its review before the parties seeking the endorsement of the court.

Please do not hesitate to call Mr. David Frederick (512-469-6000) or Mr. Eric Schaeffer (202-263-4440), both counsel for Plaintiffs, if you have any questions regarding details of the case. Mr. Adam Kushner, Director of Air Enforcement at EPA, is also familiar with many of the details of the case. He may be reached at (202) 564-7979.

Thank you for your time and attention.

Sincerely,

Mr. David Frederick
Counsel for Plaintiffs

Cc: Mr. Stephen Johnson
Mr. Michael Mukasey
Mr. Eric Schaeffer
Mr. Adam Kushner

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
TEXARKANA DIVISION

PUBLIC CITIZEN, et al.,)
)
Plaintiffs,)
)
v.)
)
AMERICAN ELECTRIC POWER) Civil Action No.
COMPANY, INC., et al.,) 5:05-cv-00039-DF
)
Defendants.)
)

CONSENT DECREE

WHEREAS, the Public Citizen and the Sierra Club (collectively "Plaintiffs") served notice of intent to sue letters ("Notice Letters") dated July 13, 2004, June 2, 2005, and September 27, 2006, and filed a Complaint on March 9, 2005, and Amended Complaints on August 12, 2005, and July 26, 2006 (collectively, "Complaints") against American Electric Power Company, Inc. ("AEP") and Southwestern Electric Power Company ("SWEPCO") (collectively, "Defendants") pursuant to Section 7604(a) of the Clean Air Act (the "Act") and 28 U.S.C. § 1331, for injunctive relief and civil penalties for alleged violations of the Act at the Welsh Power Plant ("Welsh Plant") located in Pittsburg, Texas, including but not limited to:

(a) the Prevention of Significant Deterioration ("PSD") provisions in Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-92, and permits issued to implement the PSD program;

(b) the New Source Performance Standards ("NSPS") in Section 111 of the Act, 42 U.S.C. § 7411, and related permit provisions;

(c) certain provisions of the Texas State Implementation Plan ("SIP"), approved under Section 110 of the Act, 42 U.S.C. § 7410, and permits incorporating these provisions; and

(d) the provisions of Title V of the Act, 42 U.S.C. § 7661 *et seq.*, and the Title V permits issued by the State of Texas;

WHEREAS, in their Complaints, Plaintiffs allege, *inter alia*, that Defendants failed to obtain the necessary permits and install the controls required by the Act, and that Defendants violated various PSD, NSPS, SIP and/or preconstruction and/or operating permit conditions at Welsh Plant;

WHEREAS, Defendants have denied and continue to deny the violations alleged in the Complaints; maintain that they have been and remain in compliance with the applicable requirements of the Act, the PSD program, the NSPS, the Texas SIP, and the applicable preconstruction and operating permits, and are not liable for civil penalties or injunctive relief; and state that they consent to the obligations imposed by this Consent Decree solely to avoid the costs and uncertainties of litigation;

WHEREAS, prior to and since their receipt of the Notice Letters, Defendants have installed and continue to install replacement components in the particulate matter pollution control equipment, including the installation of rigid electrodes within the electrostatic precipitators, installation of improved control systems, and installation and maintenance of improved sootblowers, that have reduced and will continue to reduce opacity and PM emissions;

WHEREAS, the Parties have negotiated in good faith and have reached a settlement of the issues raised in the Notice Letters and the Complaints;

WHEREAS, the Parties have consented to entry of this Consent Decree without trial of any issue, and without any admission, adjudication or determination of liability;

WHEREAS, subsequent to the Parties' agreement in principle to resolve this matter, but prior to the lodging of this Consent Decree with the Court, Defendants received a Notice of Violation ("NOV") dated February 5, 2008, issued by the United States Environmental Protection Agency ("U.S. EPA"), containing allegations similar or identical to some of the allegations made by Plaintiffs in their Notice Letters and/or Complaints;

and

WHEREAS, the Parties agree, and the Court by entering this Consent Decree finds, that this Consent Decree is fair, reasonable, and in the public interest; and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter;

NOW, THEREFORE, without any admission of fact or law, and without any admission of the violations alleged in the Complaints, Notice Letters and otherwise; it is hereby ORDERED, ADJUDGED, AND AGREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over this action, the subject matter herein, and the Parties consenting hereto, pursuant to 28 U.S.C. § 1331 and Section 7604(a) of the Act. Venue is proper in the Eastern District of Texas under Section 7604(c)(1) of the Act, and 28 U.S.C. § 1391(b), because the Welsh Plant is located in this district.

II. APPLICABILITY

2. Upon entry, the provisions of this Consent Decree shall apply to and be binding upon the Parties, their successors and assigns.

III. DEFINITIONS

3. "Clean Air Act" or "Act" means the federal Clean Air Act, 42 U.S.C. §§7401- 7671q.

4. "Consent Decree" or "Decree" means this Consent Decree.

5. "Defendants" means American Electric Power Company, Inc. and Southwestern Electric Power Company.

6. "Effective Date" means the date this Consent Decree is approved or signed by the United States District Judge and entered as a final order of the Court, following notice to and an opportunity for objections to be filed by U.S. EPA.

7. "NSPS" means New Source Performance Standards within the meaning of Part A of Subchapter I, of the Clean Air Act, 42 U.S.C. § 7411, 40 C.F.R. Part 60.

8. "Parties" means Plaintiffs and Defendants.

9. "Plaintiffs" means Public Citizen and Sierra Club.

10. "PM" means particulate matter.

11. "PM Continuous Emissions Monitors" or " PM CEMs" means devices for measuring particulate matter emissions that is installed, operated and maintained in accordance with the requirements of 40 CFR §60.49Da(v).

12. "PSD" means Prevention of Significant Deterioration within the meaning of Part C of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470 - 7492 and 40 C.F.R. Part 52.

13. "Renewable Energy" means energy produced from generation resources utilizing wind power, solar power, hydroelectric power or any other noncarbon energy production process.

14. "Unit" means, solely for the purposes of this Consent Decree, collectively, the coal pulverizer, stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine and boiler, and all ancillary equipment, including pollution control equipment and systems necessary for the production of electricity.

15. "Welsh Plant" means, for purposes of this Consent Decree, the three pulverized coal-fired units located at the Welsh Power Plant, located in Pittsburg, Texas.

16. "Welsh Plant Unit" means any one of the three pulverized coal-fired units located at Welsh Plant.

IV. PM EMISSION MONITORING

A. PM Emission Monitor Installation and Operation

17. By no later than December 31, 2010, SWEPCO will install, calibrate, operate and maintain PM CEMs on each of the three Welsh Plant Units, as specified below. Each PM CEM shall include a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on an hourly average basis, and a diluent monitor used to convert the concentration to units of lb/mmBtu. SWEPCO will maintain, in an electronic database, the hourly average emission values produced by all PM CEMs in lb/mmBtu. Except for periods of monitor calibration and maintenance, SWEPCO shall use reasonable efforts to keep the PM CEMs operating and producing data whenever any Unit served by a PM CEMs is synchronized with an electric utility

distribution system, through the time that Unit ceases to combust coal and the fire is out in the boiler.

B. Demonstration that PM CEMs Are Infeasible

18. SWEPCO shall operate and maintain the PM CEMs for a period of at least two (2) years on each of the Welsh Plant Units. After two (2) years of operations, SWEPCO may attempt to demonstrate that it is infeasible to continue operating the PM CEMs. As part of this demonstration, SWEPCO shall submit an alternative PM monitoring plan for review and approval by Plaintiffs. The plan shall explain the basis for ceasing operation of the PM CEMs, and propose an alternative PM monitoring plan. If Plaintiffs reject the alternative PM monitoring plan proposed by SWEPCO, or reject SWEPCO's claim that it is infeasible to continue operating the PM CEMs, such disagreement is subject to Section VIII (Dispute Resolution).

19. Operation of the PM CEMs shall be considered no longer feasible if: (a) the PM CEMs cannot be kept in proper condition for sufficient periods of time to produce reliable, adequate, or useful data consistent with the QA/QC protocol, or (b) SWEPCO demonstrates that recurring, chronic, or unusual equipment adjustment or servicing needs in comparison to other types or forms of PM monitoring cannot be resolved through reasonable expenditures of resources. If Plaintiffs concur or the Court determines that SWEPCO has demonstrated pursuant to this Paragraph that operation is no longer feasible, SWEPCO will be entitled to discontinue operation of and remove the PM CEMs.

20. Until Plaintiffs approve SWEPCO's claim of infeasibility and an alternative PM monitoring plan, or until the conclusion of any Dispute Resolution proceeding under Section VIII of this Consent Decree, SWEPCO shall continue to

operate the PM CEMs. If Plaintiffs have not given SWEPCO written notice of their agreement with or rejection of SWEPCO's claim and proposal under Paragraph 17 within one hundred twenty (120) days of receipt of the proposal, the claim and proposal shall be deemed approved by Plaintiffs.

C. PM Compliance Method

21. Stack testing shall be used to determine compliance with the PM emission limitations contained in SWEPCO's permits, however, data from PM CEMS shall be used, at a minimum, to monitor progress in reducing PM emissions.

22. Nothing in this Consent Decree is intended to, or shall, alter or waive any applicable law (including but not limited to any defenses, entitlements, challenges, or clarifications related to the Credible Evidence Rule, 62 Fed. Reg. 8314 (February 24, 1997)) concerning the use of data for any purpose under the Act generated either by the reference methods specified herein or otherwise.

V. ADDITIONAL COMMITMENTS

A. Renewable Energy

23. By no later than December 31, 2010, SWEPCO will provide proof to Plaintiffs that it has secured long-term purchase power agreements or entered into equivalent alternative arrangements to secure Renewable Energy from 65 MW of new Renewable Energy generation capacity located in Arkansas, Texas, and/or Louisiana. Power purchase agreements or other arrangements to which SWEPCO has a binding contractual commitment as of the date of lodging of this Consent Decree with the Court cannot be used to satisfy this obligation.

24. Implementation of the Renewable Energy obligations imposed by this Consent Decree is subject to SWEPCO obtaining required regulatory approvals from its state public service commissions and other applicable regulators, including approvals necessary for full cost recovery through retail rates. If SWEPCO has sought and is unable to obtain such approvals from regulators in any of the three states with jurisdiction over SWEPCO, despite its timely and reasonable efforts, SWEPCO shall have no further obligation with respect to any portion of the Renewable Energy commitments under this Consent Decree for which approval has not been obtained.

25. Nothing in this Section V shall preclude SWEPCO from relying on the investments made, or power purchase contracts entered into pursuant to this Consent Decree to demonstrate compliance with, seek renewable energy credits for, or otherwise satisfy the requirements of or participate in any federal, state or local statutory or regulatory programs regarding Renewable Energy or climate change-related requirements.

B. Mitigation Projects

26. SWEPCO shall implement and/or fund the Mitigation Projects described in this Consent Decree in compliance with the approved plans and schedules for such projects and other terms of this Consent Decree. SWEPCO shall expend moneys and/or implement projects cumulatively valued at no less than $2 million. SWEPCO shall fund and/or implement such projects over the period beginning sixty (60) days after the entry of this Consent Decree and ending on December 31, 2012. SWEPCO may propose

establishing one or more qualified settlement funds within the meaning of Treas. Reg. §1.468B-1 in conjunction with one or more Mitigation Projects.

27. In partial satisfaction of the obligation to undertake Mitigation Projects, by no later than December 31, 2008, SWEPCO shall arrange for the installation of one ambient PM monitoring station to monitor and classify by size fraction the PM in the ambient air at a location to be determined in consultation with the Texas Commission of Environmental Quality ("TCEQ") within TCEQ Region 5. SWEPCO shall provide the necessary funds for installation, certification, calibration, operation, and maintenance of the monitor through December 31, 2012.

28. By no later than March 31, 2009, SWEPCO shall develop and provide to Plaintiffs a proposed plan for the balance of the $2 million provided for Mitigation Projects under this Section V of this Consent Decree, and an estimate of the amounts expended and any remaining amount of funding required to fully implement the ambient PM monitoring project required by Paragraph 26 of this Consent Decree. Defendants shall certify, as part of the plan submitted to Plaintiffs, that Defendants are not otherwise required by law to perform any of the Projects described in the plan, that Defendants are unaware of any other person who is required by law to perform any of the Projects, and that Defendants will not use any Project, or portion thereof, to satisfy any obligations that either may have under other applicable requirements of law, including any applicable renewable portfolio standards. Mitigation Projects that may be eligible to be included in the plan include, but are not limited to: (a) projects that reduce or eliminate emissions of sulfur dioxide, nitrogen oxides, mercury or other hazardous air pollutants or PM, at the Welsh Plant or at the Welsh Plant Units; (b) projects that provide improved monitoring of emissions or other

compliance requirements at the Welsh Plant; (c) projects that produce reductions in emissions of sulfur dioxide, nitrogen oxides, mercury or other hazardous air pollutants or PM at other emission sources in Texas; (d) projects that reduce auxiliary loads or other energy requirements at the Welsh Plant or customer locations in Texas served by SWEPCO; (e) projects that reduce emissions from motor vehicles or non-road engines operated by SWEPCO or located at customer locations in Texas served by SWEPCO (f) projects that improve air quality or the monitoring of air quality in Class I areas in states served by SWEPCO; and/or (g) projects that result in the acquisition and/or restoration of ecologically significant areas in states served by SWEPCO.

29. Plaintiffs shall review and approve the plan, or provide comments or suggestions to revise the plan to SWEPCO within sixty (60) days of receipt. If Plaintiffs fail to provide comments within sixty (60) days, SWEPCO shall implement the plan as proposed. If Plaintiffs timely provide comments or suggestions on the plan, the Parties shall have an additional sixty (60) days to reach agreement on the plan. If the Parties are unable to reach agreement on the elements of the plan within one hundred twenty (120) days of Plaintiffs' receipt of the plan, the Parties shall submit the matter to the Court for resolution pursuant to Section VIII (Dispute Resolution).

30. SWEPCO shall implement the plan approved by Plaintiffs or the Court in accordance with the schedule therein (as modified, if necessary, to account for the passage of time during any Dispute Resolution proceedings), and shall maintain, and present to Plaintiffs upon request, all documents to substantiate the amounts expended to implement the Mitigation Projects. SWEPCO shall provide documents to Plaintiffs within thirty (30) days of a request for the documents.

31. Within sixty (60) days following the completion of each Mitigation Project required under this Consent Decree (including any applicable periods of demonstration or testing), SWEPCO shall submit to Plaintiffs a report that documents the date that the Mitigation Project was completed, SWEPCO's results of implementing the Mitigation Project, including the emission reductions or other environmental benefits achieved, and the amount expended by SWEPCO in implementing the Mitigation Project.

C. PM CAM Plan

32. At the time SWEPCO submits its 2009 Title V renewal application for the Welsh Plant, SWEPCO will include a compliance assurance monitoring plan that will be used to demonstrate compliance with PM emission limits that are applicable requirements in the Title V permit for the Welsh Plant Units.

VI. RELEASE AND RESOLUTION OF CLAIMS

33. Entry of this Consent Decree shall resolve all claims of Plaintiffs relating to any activities, omissions, practices, or events at the Welsh Plant that first occurred or could have been alleged to occur prior to the Effective Date, including but not limited to those claims and actions alleged in the Complaints and Notice Letters in this civil action.

34. Plaintiffs specifically release any and all claims alleging violations of the PSD program or any other preconstruction permitting requirements allegedly applicable to the Welsh Plant based on activities, omissions, practices, or events that occurred or could have been alleged to occur prior to the Effective Date of this Consent Decree, and that occur at any time prior to the termination of this Consent Decree.

35. Plaintiffs specifically release any and all claims related to whether the PM emission limits appearing in SWEPCO's permits for the Welsh Plant apply to the filterable, condensable, or combined total PM emitted by the units, and any and all claims alleging violations of those PM emission limits, based on activities, omissions, practices, or events that occurred at the Welsh Plant prior to the Effective Date of this Consent Decree, and that occur at any time prior to the termination of this Consent Decree.

36. Plaintiffs further release any and all claims related to the allegations made in the Notice Letters dated July 13, 2004, and March 28, 2005, concerning SWEPCO's Knox Lee Power Plant located in Longview, Texas.

37. Plaintiffs agree not to seek any relief at the Welsh Plant with respect to any activities, omissions, practices or events that occurred or were in existence at the Welsh Plant as of the date this Consent Decree is lodged with the Court, from any state, federal, or local court, agency, commission, department, or other body, whether through petitions, requests, demands, claims, suits, appeals, or any other action. However, this Consent Decree does not restrain Sierra Club's continued involvement in the 42 U.S.C. § 7413(a)(5) petition it and Environmental Defense Fund have filed with EPA regarding the Texas PSD Program, provided that Sierra Club shall not make any additional allegations concerning the Welsh Plant that identify any activities, omissions, practices or events that occurred or were in existence at the Welsh Plant as of the date this Consent Decree beyond those allegations already made in the petition. Furthermore, Sierra Club is not restrained from amending the petition or filing a new 42 U.S.C. § 7413(a)(5) petition that does not reference or draw evidentiary examples from the Welsh Plant. The

exception for the 42 U.S.C. § 7413(a)(5) petition(s), above, does not extend to any other petition, request, demand, claim, suit, appeal, or any other action.

38. Within five (5) business days after the Effective Date of this Consent Decree, Plaintiffs will voluntarily dismiss with prejudice the actions filed in *Sierra Club, et al., v. TCEQ*, Cause No. D-1-GN-07-001173 and *Sierra Club, et al., v. TCEQ*, Cause No. D-1-GN-07-002187 in the Travis County District Court in Austin, Texas, which on January 18, 2008, were consolidated into Cause No. D-1-GN-07-001173.

VII. *FORCE MAJEURE*

39. For purposes of this Consent Decree, a "*Force Majeure* Event" shall mean an event that has been or will be caused by circumstances beyond the control of Defendants, their contractors, or any entity controlled by Defendants that delays or impedes compliance with any provision of this Consent Decree or otherwise causes a violation of any provision of this Consent Decree despite Defendants' best efforts to fulfill the obligation. "Best efforts to fulfill the obligation" include using best efforts to anticipate any potential *Force Majeure* Event and to address the effects of any such event (a) as it is occurring and (b) after it has occurred, such that the delay or violation is minimized.

40. If any event occurs or has occurred that may delay compliance with or otherwise cause a violation of any obligation under this Consent Decree, as to which Defendants intend to assert a claim of *Force Majeure*, Defendants shall notify Plaintiffs in writing as soon as practicable, but in no event later than twenty-one (21) days following the date that the Defendants first knew, or by the exercise of due diligence should have known, of the event. In this notice, Defendants shall describe the anticipated length of time that the delay or violation may persist, the cause or causes of the delay or

violation, all measures taken or to be taken by Defendants to prevent or minimize the delay or violation, the schedule by which Defendants propose to implement those measures, and Defendants' rationale for attributing a delay or violation to a *Force Majeure* Event. Defendants shall adopt all reasonable measures to avoid or minimize such delays or violations. Defendants shall be deemed to know of any circumstance which Defendants or any entity controlled by Defendants knew or should have known.

41. The Plaintiffs shall notify Defendants in writing regarding Defendants' claim of *Force Majeure* within twenty (20) business days of receipt of the notice provided under the preceding Paragraph. If the Plaintiffs agree that a delay in performance has been or will be caused by a *Force Majeure* Event, the Parties shall stipulate to an extension of deadline(s) for performance of the affected compliance requirement(s) by a period equal to the delay actually caused by the event. In such circumstances, an appropriate modification shall be made pursuant to Section XIX (Modification) of this Consent Decree.

42. If the Plaintiffs do not accept Defendants' claim of *Force Majeure*, or if the Parties cannot agree on the length of the delay actually caused by the *Force Majeure* Event, the matter shall be resolved in accordance with Section XII (Dispute Resolution) of this Consent Decree.

43. Unanticipated or increased costs or expenses associated with the performance of Defendants' obligations under this Consent Decree shall not constitute a *Force Majeure* Event.

44. The Parties agree that, depending upon the circumstances related to an event and Defendants' response to such circumstances, the kinds of events listed below

are among those that could qualify as *Force Majeure* Events within the meaning of this Section: construction, labor, equipment, or permitting delays; acts of God; acts of war or terrorism; and orders by a court, a government official, government agency, or other regulatory body acting under and authorized by applicable law that denies approval for a project, including any Mitigation Project or Renewable Energy project. Depending upon the circumstances and Defendants' response to such circumstances, failure of a federal, state, or local agency or commission to issue a necessary permit, license, approval or order may constitute a *Force Majeure* Event where the failure of the authority to act is beyond the control of Defendants and Defendants have taken all steps available to them to obtain the necessary permit, license, approval or order, including, but not limited to: submitting a complete permit application; responding to requests for additional information by the permitting authority in a timely fashion; and accepting lawful permit terms and conditions after expeditiously exhausting any legal rights to appeal terms and conditions imposed by the permitting authority.

45. As part of the resolution of any matter submitted to this Court under Section VIII (Dispute Resolution) of this Consent Decree regarding a claim of *Force Majeure*, the Parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by Plaintiffs or approved by the Court, or excuse non-compliance with any other requirement of this Consent Decree attributable to a *Force Majeure* event.

VIII. DISPUTE RESOLUTION

46. The dispute resolution procedure provided by this Section shall be available to resolve all disputes arising under this Consent Decree, including any alleged breach of this Consent Decree by one of the Parties.

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

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

49. If the Parties are unable to resolve the dispute through the informal process described above, the disputing Party waives its rights to further dispute the issue unless, within ten (10) business days of the conclusion of the period for informal resolution provided in Paragraph 48, it files a petition with the Court describing the dispute and serves it on the other Parties. The other Parties shall have twenty (20) business days after the receipt of the petition to file and serve a written response.

50. As part of the resolution of any dispute under this Section, in appropriate circumstances the Parties by agreement, or this Court by order, may extend or modify the

schedule for the completion of the activities required under this Consent Decree to account for the delay that occurred as a result of dispute resolution, or may excuse non-compliance with any other requirement of this Consent Decree that occurred during the dispute resolution period. Defendants shall not be precluded from asserting that a *Force Majeure* Event has caused or may cause a delay in complying with the extended or modified schedule.

IX. NOTICES

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

As to Plaintiffs:

Mr. David Frederick
Lowerre, Frederick, Perales, Allmon & Rockwell
44 East Avenue, Suite 100
Austin, TX 78701

Phone: (512) 469-6000
Fax: (512) 482-9346
E-Mail: DOF@lf-lawfirm.com

And

Mr. Eric Schaeffer
Environmental Integrity Project
1920 L Street N.W., Suite 800
Washington, D.C. 20036

Phone: (202) 296-8800
Facsimile: (202) 296-8822
E-Mail: eschaeffer@environmentalintegrity.org

As to Defendants:

John M. McManus
Vice President, Environmental Services

American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215

Phone: (614) 716-1000
Fax: (614) 716-1252
E-Mail: jmmcmanus@aep.com

And

Janet J. Henry
Associate General Counsel
Environment, Health & Safety
1 Riverside plaza
Columbus, OH 43215

Phone: (614) 716-1612
Fax: (614) 716-1687
E-mail: jjhenry@aep.com

52. All notifications, communications or submissions made pursuant to this Section shall be sent either by: (a) overnight mail or delivery service; (b) certified or registered mail, return receipt requested; or (c) electronic transmission, unless the recipient is not able to review the transmission in electronic form. All notifications, communications and transmissions (a) sent by overnight, certified or registered mail shall be deemed submitted on the date they are postmarked, or (b) sent by overnight delivery service shall be deemed submitted on the date they are delivered to the delivery service. All notifications, communications, and submissions made by electronic means shall be deemed submitted on the date that sender receives written or electronic acknowledgment of receipt of such transmission.

53. Any Party may change either the notice recipient or the address for providing notices to it by serving the other Parties with a notice setting forth such new notice recipient or address.

X. NOTICE OF DECREE

54. Pursuant to 42 U.S.C. § 7604(c)(3), this Consent Decree shall be lodged with the Court and simultaneously provided to the United States for review and comment for a period not to exceed forty-five (45) days.

55. If the United States confirms that it has no objections, and does not intervene within 45 days of receipt, the Parties shall submit a joint motion to the Court seeking entry of the Consent Decree. If the United States objects or intervenes in this proceeding, the Parties will work together and with the United States to determine whether this matter can be resolved without further litigation.

XI. RETENTION OF JURISDICTION

56. The Court shall retain jurisdiction of this case after entry of this Consent Decree for purposes of implementing and enforcing the terms and conditions of the Consent Decree and adjudicating disputes under Section VIII (Dispute Resolution) until termination of the Decree.

XII. MODIFICATION

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

XIII. GENERAL PROVISIONS

58. This Consent Decree is not a permit. Compliance with the terms of this Consent Decree does not guarantee compliance with all applicable federal, state, or local laws or regulations. The provisions set forth herein do not relieve Defendants from any

obligation to comply with other state and federal requirements under the Clean Air Act at the Welsh Plant.

59. Every term expressly defined by this Consent Decree shall have the meaning given to that term by this Consent Decree.

60. This Consent Decree does not limit, enlarge or affect the rights of any Party to this Consent Decree as against any third parties, and does not provide any third party with any rights against any Party.

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

62. Certain information provided by Defendants to Plaintiffs pursuant to this Consent Decree may be considered "Confidential Information." Any information that Defendants designate as "Confidential Information" shall be maintained as confidential by the Parties consistent with the terms of the Protective Order (Dkt No. 69) entered by this Court in this matter. For purpose of Paragraph 14 of the Protective Order, which requires the return of Confidential Information upon the "termination of the action", the Parties agree that termination of the Consent Decree shall constitute "termination of the action".

63. Except as otherwise provided in this Paragraph, each Party to this action shall bear its own costs and attorneys' fees. Defendants shall reimburse Plaintiffs for a portion of their attorneys' fees and costs, up to a total of $450,000, upon presentation by counsel for Plaintiffs to counsel for Defendants of billing summaries and invoices documenting costs incurred of at least this amount, within thirty (30) days of the Effective Date of this Consent Decree.

XIV. SIGNATORIES AND SERVICE

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

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

XV. TERMINATION OF ENFORCEMENT UNDER DECREE

66. Except as provided herein, this Consent Decree shall terminate upon the earlier of (a) Defendants' completion of all requirements of this Consent Decree or (b) December 31, 2012. Should any requirement of this Consent Decree remain incomplete or disputed as of December 31, 2012, termination shall not occur until all remaining requirements have been completed and/or disputes concerning such requirements have been finally resolved or adjudicated. Termination does not require approval of the Court and is automatic upon the filing of a joint notice of termination. Any Party's failure to enter into a joint notice of termination shall be subject to Dispute Resolution as provided in Section VIII. The following provisions survive termination of this Consent Decree: Section VI (Release and Resolution of Claims), Section XVI (Final Judgment), and Paragraph 61 (concerning Confidential Information).

XVI. FINAL JUDGMENT

67. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment in the above-captioned matter between Plaintiffs and Defendants.

SO ORDERED, THIS ________ DAY OF ____________________, 2008.

____
THE HONORABLE DAVID FOLSOM
UNITED STATES DISTRICT COURT JUDGE

For Defendants:

____
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IN THE UNITED STATES DISTRICT COURT
FOR THE WESTERN DISTRICT OF PENNSYLVANIA

CITIZENS FOR PENNSYLVANIA'S FUTURE, RALPH HYSONG, ANNA MAY MOORE, ROBERT JONES,

Plaintiffs,

v.

FIRSTENERGY GENERATION CORP.,

Defendant.

CIVIL ACTION NO. 07-1412

JUDGE JOY FLOWERS CONTI

FILED ELECTRONICALLY

PARTIAL CONSENT DECREE

Whereas, in a Complaint filed on October 18, 2007, Citizens for Pennsylvania's Future (PennFuture) alleged that Defendant FirstEnergy Generation Corp. violated the Clean Air Act, 42 U.S.C. §§ 7401-7671q (CAA), and the Pennsylvania Air Pollution Control Act, 35 P.S. §§ 4001-4106, at the Bruce Mansfield plant in Shippingport, Pennsylvania (Plant); and

Whereas, this Partial Consent Decree resolves all violations alleged in Counts 1-6 of the Complaint and nothing in the Complaint, nor in this Partial Consent Decree, nor in the execution and implementation of this Partial Consent Decree, shall be treated as an admission of any violation of the CAA or its implementing regulations, or any State or local equivalent act or implementing regulations cited herein in any litigation or forum whatsoever, except that the terms of this Partial Consent Decree, and/or Defendant's failure to comply with the terms and conditions thereof, may be used by PennFuture in any action to enforce the terms of this Partial Consent Decree or as otherwise permitted by law; and

Whereas, Defendant has taken measures to reduce emissions from the Plant, and agrees to take additional measures as described herein; and

Whereas, in the same Complaint, Ralph Hysong, Anna May Moore, and Robert Jones (Individual Plaintiffs) alleged private nuisance, public nuisance, and trespass as a result of air pollution from the Plant; and

Whereas, Ralph Hysong has entered into a Confidential Settlement Agreement & Release resolving those claims; and

Whereas, the parties agree, and the Court by entering this Partial Consent Decree finds, that settlement of the claims alleged in Counts 1-6 of the Complaint without further litigation or trial of any issues is fair, reasonable, and in the public interest; and

Whereas, this Partial Consent Decree does not resolve the claims of Anna May Moore and Robert Jones.

NOW, THEREFORE, before the taking of any testimony and without the adjudication of any issue of fact or law, it is hereby ADJUDGED, ORDERED, AND DECREED as follows:

Jurisdiction and Venue

1. This Court has subject matter jurisdiction under Section 304(a) of the CAA, 42 U.S.C. § 7604(a), and 28 U.S.C. §§ 1331, 1367.

2. Venue is appropriate in the Western District of Pennsylvania under Section 304(c)(1) of the CAA, 42 U.S.C. § 7604(c)(1), and 28 U.S.C. § 1391(b), because the Plant is located in this District.

Definitions

3. "Controlled Condensation Method" means United States Environmental Protection Agency (U.S. EPA) Conditional Test Method 13 (CTM-013).

4. For purposes of Paragraphs 23 and 28, an "Exceedance" is defined as numerical opacity observations conducted in accordance with U.S. EPA Method 9 exceeding the opacity limitations established by 25 Pa. Code § 123.41.

5. "Title V Permit" means Title V/state operating permit No. 04-00235 issued by the Pennsylvania Department of Environmental Protection (Pennsylvania DEP) to Defendant for the Plant as revised on September 19, 2005, as it may from time to time be amended, modified, or renewed.

6. "U.S. EPA Method 5" means "Determination of Particulate Matter from Stationary Sources", 40 C.F.R. Part 60, Appendix A-3, Method 5, and any subsequent revisions thereto.

7. "U.S. EPA Method 9" means "Visual determination of the opacity of emissions from Stationary Sources", 40 C.F.R. Part 60, Appendix A-4, Method 9, and any subsequent revisions thereto.

8. "U.S. EPA Method 201A" means "Determination of PM_{10} and $PM_{2.5}$ Emissions from Stationary Sources (Constant Sampling Rate Procedure)" as proposed by U.S. EPA at 74 Fed. Reg. 12,970 (March 25, 2009), and any subsequent revisions thereto.

9. "U.S. EPA Method 202" means "Dry Impinger Method for Determining Condensable Particulate Emissions from Stationary Sources", as proposed by U.S. EPA at 74 Fed. Reg. 12,970 (March 25, 2009), and any subsequent revisions thereto.

10. "Sulfuric Acid Mist" means the sum of sulfur trioxide (SO3), gaseous sulfuric acid, and sulfuric acid mist.

Plant Improvements

Units 1 and 2 Improvements

11. Defendant shall install continuous emission monitors for particulate matter (PM CEMS) on Units 1 and 2 by October 31, 2009, and file certification applications for the PM CEMS with Pennsylvania DEP by December 31, 2009.

12. Defendant shall install roughing mist eliminators at Unit 2 by December 31, 2010 and at Unit 1 by December 31, 2012.

13. Defendant shall improve the mist eliminator wash water systems by installing new strainers at Unit 2 by December 31, 2010 and at Unit 1 by December 31, 2011.

14. Defendant shall replace the existing primary mist eliminators at Unit 2 by December 31, 2010 and Unit 1 by December 31, 2012 to reduce the potential for scrubber carryover.

15. As of the date of entry of this Partial Consent Decree and continuing during the term of this Partial Consent Decree, Defendant shall clean the induced draft (ID) fans on Units 1 and 2, as needed, using an ID fan spray system controlled by the Plant's digital process control system to prevent operation of the ID fan sprays when stack conditions are below saturation temperature, prevent simultaneous spraying of two ID fan sprays on the same flue, and prevent

inadvertent water flow to the ID fan sprays. Nothing in this Paragraph shall prevent future improvements to the ID fan cleaning process on Units 1 and 2.

Unit 3 Improvements

16. Defendant shall install a scrubber bleed system on Unit 3 by December 31, 2009.

17. Defendant shall insulate the two flue liners in the Unit 3 stack by December 31, 2011.

Units 1, 2, and 3 Improvements

18. Defendant shall complete an assessment and issue a report regarding remedial measures for air in-leakage downstream of the economizer of Units 1, 2 and 3 (the "Air In-Leakage Report") within 18 months of the date of entry of this Partial Consent Decree. The Air In-Leakage Report will include measurements of O2 at the economizer outlets and the ID fan inlets, or an alternate method of determining overall air in-leakage. Defendant shall complete implementation of remedial measures identified in the Air In-Leakage Report during the next available scheduled outage with a duration of at least 56 days at each of Units 1, 2 and 3 and not later than 36 months after the Air In-Leakage Report is submitted.

19. Defendant shall improve the selective catalytic reduction outlet monitors by installing new nitrogen oxides/sulfur dioxide probes and installing new ammonia analyzers by December 31, 2009.

20. Defendant shall complete an assessment of the performance of the sodium bisulfide (SBS) injection lances at the current locations and at alternate locations (the "SBS Lance Report") within 12 months of the date of entry of this Partial Consent Decree. If such SBS Lance Report concludes that material improvements can be achieved through relocation of SBS lances, Defendant shall (a) complete the engineering and design for relocating SBS

injection lances at Units 1, 2, and 3 within 12 months of the SBS Lance Report and (b) complete implementation of such recommendations during the next available scheduled outage with a duration of at least 56 days at each of Units 1, 2 and 3 and not later than 36 months of the completion of engineering and design.

Continued Plantwide Measures

21. Defendant shall continue operation of SBS (or other sorbent) injection systems to minimize formation of Sulfuric Acid Mist. Defendant shall maintain an annual average SBS molar ratio of 1.0 or greater on each of Units 1, 2 and 3, to achieve a stack SO3 concentration no higher than 5 ppm (or such lower limit required by regulation or permit). This average SBS molar ratio shall be monitored by the Plant's digital process control system and reported on a calendar year basis. If Defendant transitions to another sorbent, such transition shall commence at a single Unit and be accompanied by testing to determine the appropriate molar ratio to control Sulfuric Acid Mist to 5 ppm (or such lower limit required by regulation or permit). Following such molar ratio testing, Defendant shall maintain an annual average molar ratio as determined by such testing utilizing another sorbent on each of Units 1, 2 and 3, which shall be monitored by the Plant's digital process control system and reported annually.

22. Defendant shall continue operation of combustion optimization system to minimize formation of soot, nitrogen oxides and carbon monoxide.

Monitoring

23. Defendant shall conduct U.S. EPA Method 9 observations of the Units 1/2 stack and the Unit 3 stack at the Plant after dissipation of the steam plume between 1:00 p.m. and 4:00 p.m. on Monday (or Tuesday), Wednesday (or Thursday) and Friday for the initial 180 days following the date of entry of this Partial Consent Decree. Over the next 540 days, the frequency

of Defendant's U.S. EPA Method 9 observations during each three consecutive calendar month period shall be determined by the number of opacity Exceedances occurring in the immediately preceding three consecutive calendar month period for each stack as follows:

Stack Exceedances	# Observations/Wk.	Day(s) Observations to be Conducted
more than 4	3	Mon. (or Tues.), Wed. (or Thurs.) and Friday
3 to 4	2	Mon. (or Tues. or Wed.) and Thurs. (or Fri.)
0 to 2	1	Mon. (or next possible day)

For purposes of this Paragraph, Defendant shall conduct U.S. EPA Method 9 observations on both the Units 1/2 stack and the Unit 3 stack for a minimum of one hour between 1:00 p.m. and 4:00 p.m. on the day(s) indicated; provided, that if observations are not possible due to circumstances beyond Defendant's control on the day indicated, Defendant shall conduct readings on the next day indicated in parenthesis, continuing as needed to succeeding days as indicated. If observations are indicated by the table above for a Friday, but are not possible due to circumstances beyond Defendant's control, Defendant shall resume the schedule indicated on the following Monday.

24. Defendant's agreement to conduct U.S. EPA Method 9 observations under this Partial Consent Decree shall not be deemed to be a waiver in any other action or proceeding of any arguments Defendant may have regarding the appropriateness of U.S. EPA Method 9 observations for determining compliance with applicable visible emission standards.

25. During the initial 720 days of this Partial Consent Decree, Defendant shall complete stack tests for particulate matter in accordance with U.S. EPA Method 5 and proposed U.S. EPA Method 201A and 202. If U.S. EPA Method 201A is not possible at the time of any stack test due to moisture, Defendant shall complete stack tests for particulate matter with U.S. EPA Method 5 and proposed U.S. EPA Method 202. Defendant shall perform testing for

particulate matter annually as required to maintain certification of the stack particulate monitors for Units 1-3.

26. Defendant shall complete stack testing of Sulfuric Acid Mist using the Controlled Condensation Method within 9 months of the date of entry of this Partial Consent Decree and, if requested by PennFuture, a second test using the Controlled Condensation Method within 18 months of the date of entry. If any Sulfuric Acid Mist levels are greater than 5 ppm during the second test, and if PennFuture requests an additional test, Defendant shall conduct a third test between 18 months and 30 months of entry of this Partial Consent Decree.

27. Tests for particulate matter under Paragraph 25 shall be conducted in accordance with Pennsylvania Code Title 25, Environmental Protection, Chapter 139.11(1), and the Pennsylvania DEP Source Testing Manual Revision 3.3, November 2000 (including but not limited to Paragraphs 2.1.2.5 and 2.1.1.10 therein). Such tests shall consist of three runs (at least one run shall be performed during a period of representative soot blowing, which is consistent with the maximum frequency and duration normally experienced for the total testing period), will be scheduled at least one month after the conclusion of a planned maintenance outage, and will utilize representative fuel.

Other Terms

28. Until December 31, 2011, Defendant shall undertake the following measures in the event that (a) the PM CEMS readings for a Unit exceed the Title V Permit limits for particulate matter five or more times in three consecutive calendar months, or (b) U.S. EPA Method 9 observations for a stack conducted in accordance with the Title V Permit and this Partial Consent Decree result in five or more Exceedances of the Title V Permit opacity limit in three consecutive calendar months:

a. analysis of such Unit's operational data;

b. review of operating and maintenance procedures;

c. review of soot control decision tree analysis;

d. training of all control room operators and production supervisors; and

e. documentation of the investigation, including steps taken to prevent its recurrence.

These measures shall be completed within 60 days of the fifth Exceedance under this Paragraph.

29. Within 10 days of the date of entry of this Partial Consent Decree, Defendant shall withdraw its pending application to Pennsylvania DEP for an alternative opacity limitation at the Plant. Under this provision, Defendant reserves its right to reapply for such a limitation in the future.

Reporting

30. Defendants shall provide copies of the following reports and other documents required under this Partial Consent Decree to PennFuture within 30 days of completion:

a. The Air In-Leakage Report;

b. The SBS Lance Report;

c. Any report regarding engineering and design for relocating SBS injection lances;

d. Annual reports of SBS or other sorbent molar ratios;

e. Stack tests;

f. Reports of investigations of air pollution episodes and/or exceedances; and

g. The withdrawal of the application for an alternative opacity limitation.

31. Until termination of this Partial Consent Decree, Defendant shall provide copies of reports and other documents regarding air quality at the Plant to PennFuture at the time of submission to Pennsylvania DEP and/or U.S. EPA. Such reports include, but are not limited to:

a. PM CEMS reports;

b. Relative accuracy test audit reports;

c. Semiannual reports under the Title V Permit;

d. Annual compliance certifications under the Title V Permit;

e. Reports to Pennsylvania DEP and/or U.S. EPA of releases of air pollution; and

f. Any stack testing not required under the Partial Consent Decree.

32. Until termination of this Partial Consent Decree, Defendant shall provide copies of U.S. EPA Method 9 observations to PennFuture as follows:

a. All U.S. EPA Method 9 observations from July 1, 2009 to the date of entry of this Partial Consent Decree shall be provided by the 15th day of the month following the date of entry;

b. From date of entry to December 31, 2010, Defendant shall provide U.S. EPA Method 9 observations for each month by the 15th day of the following month;

c. From January 1, 2011 until termination of the decree, Defendant shall provide U.S. EPA Method 9 observations for each calendar quarter by the end of the month following the end of the calendar quarter; and

d. With any notice of termination under Paragraph 42 below, Defendant shall provide all remaining observations as of the date of the notice.

33. Documents required to be provided by Defendants to PennFuture under this Partial Consent Decree shall be sent by e-mail to the following addresses:

Charles McPhedran, Law Staff Chair
PennFuture
1518 Walnut Street, Suite 1100
Philadelphia, PA 19102
mcphedran@pennfuture.org

John Baillie, Senior Attorney
PennFuture
425 Sixth Avenue, Suite 2770
Pittsburgh, PA 15219
baillie@pennfuture.org

If any documents required to be provided cannot be successfully transmitted to PennFuture by e-mail, Defendant shall send them by first class mail to the addresses in this Paragraph no later than five business days after the deadline otherwise established under this Partial Consent Decree.

General Provisions

34. Petition for Stay: Within 10 days of execution of this Partial Consent Decree, the Parties shall jointly petition the Court for a stay of proceedings in this matter based upon a settlement having been reached. In their petition, the parties shall explain their intention to have this Partial Consent Decree entered as an order of the Court following expiration of the 45-day period described in the next paragraph.

35. Government Comment or Intervention; Entry: Within 10 days of execution of this Partial Consent Decree, PennFuture shall serve this Partial Consent Decree on the Attorney General of the United States and the Administrator of U.S. EPA. If the United States does not comment or intervene within 45 days of receipt, the parties shall submit this Partial Consent Decree to the Court together with a joint motion for its entry as an Order of this Court. If the United States comments or intervenes in this proceeding, the parties will work together and with the United States determine whether this matter can still be resolved without further litigation.

At any time following comment or intervention by the United States, one or more of the parties may petition the Court to lift the stay of proceedings.

36. Pre-Date of Entry Obligations: Obligations of Defendant that pre-date the entry of this Partial Consent Decree apply upon execution of the Partial Consent Decree by the parties. However, to the extent that this Partial Consent Decree is revised due to comments or intervention by the United States, Defendant's obligation to comply with provisions affected by such revisions will be excused until fifteen days after entry of this Partial Consent Decree or the date on which Defendant's compliance would have been required absent such revision, whichever is later.

37. Costs of Litigation: Under 42 U.S.C. § 7604(d), the Court, in issuing any final order in a citizen suit under the Clean Air Act, may award costs of litigation (including reasonable attorney and expert witness fees) to any party, whenever the Court determines such award is appropriate. In settlement of the Plaintiffs' costs of litigation in this proceeding, Defendant agrees (a) to pay to PennFuture the amount of $310,000 and (b) to transfer to PennFuture the quantity of 10,000 Pennsylvania Tier 1 renewable energy credits (Pa. RECs). Payment of the amount of $310,000 shall be made no later than 60 days after entry of this Partial Consent Decree. Payment shall be made by wire transfer to Fulton Bank, Routing No. 031301422, Account No. 3623 52132. The Pa. RECs shall be generated during the reporting year starting July 1, 2009 and shall be transferred within 20 days from date of entry of this Partial Consent Decree. If Defendant fails to pay and transfer the full agreed amount and RECs under this Paragraph, PennFuture may file a motion for fees and costs with the Court, and may seek its full fees and costs in this proceeding up to and including this motion.

38. Continuing Jurisdiction: The parties agree that the Court shall maintain jurisdiction over this matter to enforce the terms of this Partial Consent Decree until such time as it is terminated in accordance with Paragraph 42 below. The parties agree that in the event of a breach of this Partial Consent Decree, the non-breaching party may pursue any rights, remedies or sanctions available under applicable laws.

39. Severability. If any provision of this Partial Consent Decree is declared invalid or unenforceable, the remaining provisions shall continue in effect.

40. Entire Agreement. This Partial Consent Decree represents the entire agreement between the parties. Prior drafts of this Partial Consent Decree and related term sheets shall not be used in any action involving the interpretation or enforcement of this Partial Consent Decree.

41. Modification: This Partial Consent Decree may be modified by written agreement of the parties, which modification shall be promptly filed with the Court.

42. Termination: This Partial Consent Decree shall terminate upon fulfillment of the Plant Improvements set forth in Paragraphs 11 to 20 of this Partial Consent Decree and other obligations herein but not later than December 31, 2014. Upon fulfillment of the Plant Improvements and other obligations herein, either party may provide notice of termination of this Partial Consent Decree to the Court and to the other party. This Partial Consent Decree shall terminate 30 days after such notice unless (a) objections are filed with the Court by the non-noticing party or (b) otherwise ordered by the Court.

43. Dismissal with Prejudice: In consideration of Defendant's obligations under this Partial Consent Decree, PennFuture agrees that the claims in Counts 1-6 of the Complaint shall be dismissed with prejudice.

44. Certification: The undersigned representatives of each party certify that

they are authorized by the party they represent to consent to this Partial Consent Decree.

Respectfully submitted,

FOR PLAINTIFFS PENNFUTURE,
RALPH HYSONG, ANNA MAY MOORE,
AND ROBERT JONES

Date: 8/17/09

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FOR DEFENDANT FIRSTENERGY
GENERATION CORP.

Charles D. Lasky
Charles Lasky
Vice President, Fossil Operations

Doug Weber
Douglas J. Weber
Senior Counsel

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

IN THE MATTER OF:

FirstEnergy Generation Corp.	:	Air Quality
P.O. Box 128	:	Visible Emissions Violations
Shippingport, PA 15077-0128	:	25 Pa. Code § 123.41

CONSENT ORDER AND AGREEMENT

This Consent Order and Agreement is entered into this 28th day of February, 2008, by and between the Commonwealth of Pennsylvania, Department of Environmental Protection (hereinafter "Department"), and FirstEnergy Generation Corp. (hereinafter "FirstEnergy").

The Department has found and determined the following:

A. The Department is the agency with the duty and authority to administer and enforce the Air Pollution Control Act of January 8, 1960, P.L. 2119 (1959), *as amended*, 35 P.S. §§ 4001-4015 ("Air Pollution Control Act"); Section 1917-A of the Administrative Code of 1929, Act of April 9, 1929, P.L. 177, *as amended*, 71 P.S. § 510-17 ("Administrative Code"); and the rules and regulations ("rules and regulations") promulgated thereunder.

B. FirstEnergy (formerly Pennsylvania Power Company) is an Ohio corporation with its corporate offices located at 76 South Main Street, Akron, Ohio 44308. (FirstEnergy and its predecessor in interest at the Site, Pennsylvania Power Company, shall be collectively referred to as "FirstEnergy").

C. FirstEnergy operates and owns (or has a leasehold interest in) the Bruce Mansfield Power Plant located in Shippingport Borough, Beaver County, Pennsylvania (hereinafter "Site"). FirstEnergy operates three utility boilers designated as Units 1, 2 and 3, at the Site. Units 1 and 2 exhaust through a 950-foot stack containing four (4) separate flues, and Unit 3 exhausts through a 650-foot stack containing two (2) separate flues. FirstEnergy operates the Site pursuant to Air Quality Title V Permit No. 04-00235 ("Permit"), which was issued by the Department on November 22, 2002, and amended thereafter.

D. Pursuant to the Department's regulatory program to reduce ozone concentrations, FirstEnergy installed low NOx burners and over-fire air, selective catalytic reduction systems, and took other operational steps to reduce nitrogen oxide ("NOx") emissions from Units 1, 2 and 3.

E. The Site's NOx controls may have had the unanticipated effect of increasing visible emissions from Units 1 and 2, and to a lesser degree, on Unit 3.

F. The installation of NOx controls at some other electric generating stations in the United States also may have increased visible emissions at those stations.

G. Visible emissions from the Site are regulated by 25 Pa. Code § 123.41, which states:

> A person may not permit the emission into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following:
>
> (1) Equal to or greater than 20% for a period or periods aggregating more than 3 minutes in any 1 hour.
>
> (2) Equal to or greater than 60% at any time.

H. On September 6, 1999, the Department entered into a Consent Order and Agreement with FirstEnergy, which, among other things, required FirstEnergy to conduct extensive studies relating to opacity conditions at similar facilities, study various fuel alternatives, install carbon monoxide analyzers in its boiler units, test combustion equipment and various blends of limestone materials, and to review flue gas flow and temperature influences on the electrostatic precipitator. FirstEnergy's efforts included working with the Department of

Energy (DOE) to implement and study the furnace injection of alkaline sorbents as part of what has become known as the DOE's SO_3 Mitigation Project. The study showed that although a 90% decrease in sulfuric acid could be achieved, long-term injection would not be feasible because of uncontrollable fouling and slagging in the boilers. FirstEnergy complied with its obligations under the September 6, 1999 Consent Order and Agreement, but violations of 25 Pa. Code § 123.41, based upon utilizing the EPA Method 9 observation technique, continued regularly at the Site.

I. On November 13, 2001, the Department entered into a second Consent Order and Agreement with FirstEnergy, which, among other things, required FirstEnergy to conduct and complete an evaluation of the visible emission effects of blending petroleum coke with coal, scrubber inlet injection technologies, and back-end technologies all the while maintaining EPA Method 9 visible emission certification for at least two (2) of its employees. Based upon the results of the petroleum coke evaluations, FirstEnergy concluded that although there was a small increase in sulfuric acid (H_2SO_4) emissions, petroleum coke blending had little to no effect on plume opacity at the Site. FirstEnergy concluded it could obtain favorable results for the reduction of visible emissions from the injection of sodium bisulfite (SBS). FirstEnergy has complied with its obligations under the November 13, 2001 Consent Order and Agreement.

J. Based upon the results of SBS injection technology evaluation, FirstEnergy committed to implement SBS technology at the Site in an effort to bring the Site into compliance with 25 Pa. Code § 123.41.

K. On May 28, 2003, the Department entered into a third Consent Order and Agreement with FirstEnergy, which required FirstEnergy to install SBS injection technology on all three boiler units, at the Site.

L. On March 10, 2003, Boiler Unit No. 1 began operation with the SBS injection system, at the Site.

M. On April 17, 2003, Boiler Unit No. 2 began operation with the SBS injection system, at the Site.

N. On January 29, 2004, Boiler Unit No. 3 began operation with the SBS injection system, at the Site.

O. FirstEnergy complied with its obligations under the May 28, 2003 Consent Order and Agreement.

P. As a result of the installation of the SBS injection technology at the Site, visible emissions from both stacks decreased, but violations of 25 Pa. Code § 123.41, based upon utilizing the EPA Method 9 observation technique, continued at the Site.

Q. On January 18, 2005, the Department entered into a fourth Consent Order and Agreement with FirstEnergy, which, among other things, required FirstEnergy to submit a Plan Approval application for an Alternate Opacity Limitation (AOL), pursuant to 25 Pa. Code § 123.45, by March 31, 2005. In addition, FirstEnergy was required to conduct and provide the results of any tests the Department deemed necessary for determining compliance with the applicable emission limitation, for AOL consideration.

R. The AOL is an administrative mechanism provided in the Pennsylvania regulations that allows eligible sources to seek and obtain an alternative visible emission standard applicable to the source (25 Pa. Code § 123.45). Any eligible source may seek an AOL.

S. On August 25, 2005, the Department modified the January 18, 2005 Consent Order and Agreement to require FirstEnergy to conduct scrubber upgrades before pursuing the AOL for which the application had already been submitted on March 31, 2005. FirstEnergy withdrew its AOL Plan Approval application on October 14, 2005.

T. FirstEnergy complied with its obligations under the January 18, 2005 Consent Order and Agreement and August 25, 2005 modification by completing the scrubber upgrades.

U. FirstEnergy conducted stack testing on each boiler unit prior to the expiration of its Permit on November 22, 2007. The stack tests were required to be performed under the conditions of the Permit. The stack tests showed that all three boiler units were in compliance with their respective mass emission standards for particulate.

V. Though FirstEnergy has taken several measures intended to reduce visible emissions from the Facility, and recent stack tests demonstrated that all three Units complied with mass emission standards for particulate, FirstEnergy's visible emissions are expected to continue to exceed the opacity limits in 25 Pa. Code § 123.41, based upon utilizing the EPA Method 9 observation technique, in the future.

W. FirstEnergy submitted a second Plan Approval application for AOL to the Department on July 16, 2007. The Department is reviewing the application, and a draft plan approval was published in the Pennsylvania Bulletin on December 1, 2007. The Department is currently accepting public comments on the application.

X. Because of air heater reliability concerns associated with SBS injection and the subsequent operating unit reliability impacts (plugging in the air heater), FirstEnergy believes it necessary to remove SBS injection from service (to allow self-cleaning to avoid plugging) for a period of up to six weeks a year, for each boiler, for the purpose of maintaining reliable operation of the boilers.

Y. EPA Method 9 readings of the Bruce Mansfield stacks are very difficult to accurately complete due to the residual moisture (from the scrubber) in the plumes and because the background often does not provide optimal contrast with the plume. FirstEnergy maintains that EPA Method 9 (40 CFR part 60 Appendix A) is not appropriate for determining opacity from stacks with multiple flues such as the two stacks at the Site.

Z. This Consent Order and Agreement affords FirstEnergy time to complete the AOL process which includes, among other things, stack testing in conjunction with EPA Method 9 observations during the continued operation of the boiler units at the Site, recognizing the likelihood of occasional exceedances of the opacity limitations prescribed in 25 Pa. Code § 123.41. During this period, FirstEnergy will analyze and take additional measures that may have a beneficial effect on visible emissions.

AA. The violations described in Paragraph V above, constitute unlawful conduct under Section 8 of the Air Pollution Control Act, 35 P.S. § 4013, and subject FirstEnergy to civil penalty liability under Section 9.1 of the Air Pollution Control Act, 35 P.S. § 4009.1.

After full and complete negotiation of all matters set forth in this Consent Order and Agreement and upon mutual exchange of covenants contained herein, the parties, desiring to avoid litigation and intending to be legally bound, it is hereby ORDERED by the Department and agreed to by FirstEnergy as follows:

1. Authority. This Consent Order and Agreement is an Order of the Department authorized and issued pursuant to Sections 4(9)(i) and 10.1 of the Air Pollution Control Act, 35 P.S. §§ 4004(9)(i) and 4010.1, and Section 1917-A of the Administrative Code, 71 P.S. § 510-17.

2. Findings.

a. FirstEnergy agrees that the findings in Paragraphs A through AA are true and correct and, in any matter or proceeding involving FirstEnergy and the Department, First Energy shall not challenge the accuracy or validity of these findings.

b. The parties do not authorize any other persons to use the findings in this Consent Order and Agreement in any matter or proceeding.

3. Corrective Action.

a. FirstEnergy shall continue to maintain EPA Method 9 visible emission reading certification for at least two (2) FirstEnergy employees.

b. FirstEnergy shall conduct weekly EPA Method 9 visible emission readings on both stacks for a minimum of one hour on Monday afternoon between 1:00 p.m. and 4:00 p.m.; provided, that if for circumstances beyond FirstEnergy's control it is not feasible to conduct such testing on Monday, then such readings shall be attempted on Tuesday afternoon between 1:00 p.m. and 4:00 p.m.; if for circumstances beyond FirstEnergy's control it is not feasible to conduct such testing on Tuesday, then such readings shall be attempted on Wednesday afternoon between 1:00 p.m. and 4:00 p.m.; if for circumstances beyond FirstEnergy's control it is not feasible to conduct such testing on Wednesday, then such readings shall be attempted on Thursday afternoon between 1:00 p.m. and 4:00 p.m. and if necessary Friday afternoon between 1:00 p.m. and 4:00 p.m., in order to maximize the likelihood of obtaining one successful reading on each stack for each week.

c. FirstEnergy shall install a particulate monitoring system ("PMS") in the two flues of the stack for Unit 3 on or before June 30, 2008. Upon installation, FirstEnergy shall seek certification of such PMS devices from the Department.

d. Following the certification of the PMS, FirstEnergy shall begin submitting PMS reports of deviations from 25 Pa. Code § 123.11(a)(3), based on particulate emission data averaged over each boiler operating day (as defined under 40 C.F.R. 60.41Da), to the Department on or before the 10th day of every month, beginning the month succeeding the certification of the PMS.

e. Following the certification of the PMS, FirstEnergy shall begin submitting quarterly PMS reports, of all data to the Department on or before the 10th day of every April, July, October and January, through the term of this COA.

f. FirstEnergy shall install a PMS in the four flues of the common stack for Units 1 and 2 within 180 days of receiving certification from the Department for each PMS in the stack for Unit 3. Upon installation, FirstEnergy shall seek certification of such PMS devices from the Department.

g. Following the certification of the PMS for the common stack for Units 1 and 2, FirstEnergy shall begin submitting PMS data reports in the same manner specified in Paragraphs 3d. and 3e., above.

h. FirstEnergy shall procure and install a combustion optimization system for each boiler unit at the Site on or before November 30, 2008. This computerized system shall collect plant operating data, for example, select air flows and pressures, coal flow, oxygen concentrations, and equipment position parameters into a centralized database. FirstEnergy shall then use collected plant operating data to make necessary adjustments to the boiler units and/or their respective air pollution control equipment, so as to operate said equipment in a manner best suited for compliance with the Air Pollution Control Act ("APCA").

i. FirstEnergy shall conduct a study of the air flow distribution in the scrubber vessels of Boiler Units 1 and 2 on or before June 30, 2008. This study shall include modeling of the scrubber vessel from the scrubber inlet ductwork to the scrubber outlet ductwork, including the "plumb bob", the scrubber reaction tank area, the scrubber tray, and the mist eliminators. The purpose of this modeling will be to determine what, if any, significant particle and gas flow variations exist that might contribute to carryover (uncollected scrubber particulate that may occasionally become entrained in the flue gas, and exhausted through the stack as rain out particulate) from the scrubber. Study results and recommendations shall be provided to the Department on or before August 31, 2008.

j. FirstEnergy shall conduct a study of industry practices for the cleaning of mist eliminators and induced draft fans on or before May 31, 2008. The purpose of this study is to identify optimal cleaning and operating practices to minimize the potential for stack rainout events. FirstEnergy shall then analyze and use the results of this study to develop a schedule for implementation of the most optimal cleaning and operating practices identified in the study. The implementation schedule shall be submitted to the Department for approval by December 31, 2008. If approved by the Department, the implementation plan shall be incorporated into the pending Permit.

k. FirstEnergy shall provide oral notification to the Shippingport police within one (1) hour of becoming aware of any rain out events.

l. FirstEnergy shall operate its SBS injection system in the manner most recently authorized by the Department, and shall provide the Department with 7 days advanced written notification and justification before it removes the SBS injection from service on any of the three boiler units. FirstEnergy may remove SBS injection from service on each operating boiler unit (when necessary to allow self-cleaning to avoid plugging) for a period of up to six (6) weeks a year, for the purpose of maintaining reliable operation of the boilers. FirstEnergy may not remove SBS injection from service on more than one boiler unit at the same time.

m. In the event of an emergency situation either directly or indirectly relating to SBS injection, the provisions in Paragraph h. above, shall not apply.

n. FirstEnergy shall at all times, use sound engineering and operational procedures to minimize stack opacity.

4. Civil Penalty Settlement.

a. In resolution of the Department's claim for civil penalties for violations of 25 Pa. Code § 123.41 at the Site during the term of this Consent Order and Agreement which the Department is authorized to pursue under Section 9.1 of the Air Pollution Control Act, 35 P.S. § 4009.1, FirstEnergy shall pay a monthly civil penalty in the amount of $10,000 due on or before the 15th day of every month beginning on March 15, 2008 until December 15, 2009 or until the Department issues an alternate opacity standard for the Site, whichever occurs first.

b. For any month in which an SBS injection is taken out of service on any of the boiler units, FirstEnergy shall pay $5,000 in addition to the $10,000 monthly civil penalty specified in Paragraph 4a above.

c. For any month in which two or more Method 9 emission readings, whether, by FirstEnergy and/or the Department, or one or more such readings from each party, exceed 60% opacity, FirstEnergy shall pay $5,000 in addition to the $10,000 monthly civil penalty specified in Paragraph 4a above.

d. FirstEnergy's obligation to pay civil penalties under this paragraph shall terminate on December 15, 2009, or earlier if FirstEnergy achieves three (3) consecutive calendar months of valid Method 9 readings, without an exceedance being observed by FirstEnergy or the Department of the standards set forth in 25 Pa. Code § 123.41, or the Department has approved an AOL. Three consecutive calendar months of valid Method 9 readings shall be defined as at least one complete, uninterrupted hour (240 readings) of EPA Method 9 observations in every week in three consecutive months. In the event FirstEnergy meets the requirements set forth above as to only one stack, FirstEnergy shall continue to pay a $5,000.00 monthly civil penalty pursuant to Paragraph 4(a) for violations of 25 Pa. Code § 123.41 for the remaining stack, in addition to any penalties that may be due under Paragraphs 4(b) and 4(c).

5. Stipulated Civil Penalties.

a. In the event FirstEnergy fails to comply in a timely manner with any term or with any term or provision of Paragraph 3 of this Consent Order and Agreement, FirstEnergy, shall be in violation of this Consent Order and Agreement and, in addition to other applicable remedies, shall pay a civil penalty in the amount of $1000.00 per day for each violation of this Consent Order and Agreement.

b. If, during the term of this Consent Order and Agreement the Department determines that violations of 25 Pa. Code § 123.41 have significantly worsened in terms of frequency or extent from violations observed in September 2004, the Department may, by providing FirstEnergy ten (10) days prior written notice, terminate the civil penalty provisions set forth in Paragraph 4 of this Consent Order and Agreement with respect to a specific month, and assess civil penalties for such violations pursuant to the APCA; provided however, that FirstEnergy shall have the right to request a conference with the Air Quality Program Manager prior to the expiration of such ten day notice period, to discuss such violations and the progress under this Consent Order and Agreement, prior to the termination of the civil penalty provision. FirstEnergy reserves the right to challenge any civil penalty assessed in excess of the amounts set forth in Paragraph 4.

c. Stipulated civil penalties shall be payable monthly on or before the fifteenth day of each succeeding month. All civil penalty payments shall be made by corporate check or the like made payable to the "Commonwealth of Pennsylvania, Clean Air Fund" and sent to the attention of Mark A. Wayner, Regional Air Quality Program Manager, Department of Environmental Protection, 400 Waterfront Drive, Pittsburgh, PA 15222-4745.

d. Any payment under this paragraph shall neither waive FirstEnergy's duty to meet its obligations under this Consent Order and Agreement nor preclude the Department from commencing an action to compel FirstEnergy's compliance with the terms and conditions of this Consent Order and Agreement. The payment resolves only FirstEnergy's liability for civil penalties arising from the violation of 25 Pa. Code § 123.41 and this Consent Order and Agreement for which the payment is made.

6. Additional Remedies.

a. In the event FirstEnergy fails to comply with any provision of this Consent Order and Agreement, the Department may, in addition to the remedies prescribed herein, pursue any remedy available for a violation of an order of the Department, including an action to enforce this Consent Order and Agreement.

b. The remedies provided by this paragraph and Paragraph 5 (Stipulated Civil Penalties) are cumulative and the exercise of one does not preclude the exercise of any other. The failure of the Department to pursue any remedy shall not be deemed to be a waiver of that remedy. The payment of a stipulated civil penalty, however, shall preclude any further assessment of civil penalties for the violation for which the stipulated civil penalty is paid.

7. Reservation of Rights. The Department reserves the right to require additional measures to achieve compliance with applicable law. FirstEnergy reserves the right to challenge any action in which the Department may take to require those measures.

8. Liability of Operator. FirstEnergy shall be liable for any violations of the Consent Order and Agreement, including those caused by, contributed to, or allowed by its officers, agents, employees, or contractors. FirstEnergy also shall be liable for any violation of this Consent Order and Agreement caused by, contributed to, or allowed by its successors and assigns.

9. Transfer of Site.

a. The duties and obligations under this Consent Order and Agreement shall not be modified, diminished, terminated or otherwise altered by the transfer of any legal or equitable interest in the Site or any part thereof.

b. If FirstEnergy intends to transfer any legal or equitable interest in the Site which is affected by this Consent Order and Agreement, FirstEnergy shall serve a copy of this Consent Order and Agreement upon the prospective transferee of the legal and equitable interest at least thirty (30) days prior to the contemplated transfer and shall simultaneously inform the Southwest Regional Office of the Department of such intent.

10. Correspondence with Department. All correspondence with the Department concerning this Consent Order and Agreement shall be addressed to:

Mark A. Wayner
Air Quality Program Manager
Department of Environmental Protection
400 Waterfront Drive
Pittsburgh, PA 15222-4745
Phone: (412) 442-4000
Fax: (412) 442-4194

11. Correspondence with FirstEnergy. All correspondence with FirstEnergy concerning this Consent Order and Agreement shall be addressed to:

Frank A. Lubich
Vice President
FirstEnergy Generation Corp.
Bruce Mansfield Plant
P.O. Box 128
Shippingport, PA 15077-0128
Phone: (724) 643-2300
Fax: (724) 643-2220

FirstEnergy shall notify the Department whenever there is a change in the contact person's name, title, or address. Service of any notice or any legal process for any purpose under this Consent

Order and Agreement, including its enforcement, may be made by mailing a copy by first class mail to the above address.

12. Force Majeure.

a. In the event that FirstEnergy is prevented from complying in a timely manner with any time limit imposed in this Consent Order and Agreement solely because of a strike, fire, flood, act of God, or other circumstances beyond FirstEnergy's control and which FirstEnergy, by the exercise of all reasonable diligence, is unable to prevent, then FirstEnergy may petition the Department for an extension of time. An increase in the cost of performing the obligations set forth in this Consent Order and Agreement shall not constitute circumstances beyond FirstEnergy's control. FirstEnergy's economic inability to comply with any of the obligations of this Consent Order and Agreement shall not be grounds for any extension of time.

b. FirstEnergy shall only be entitled to the benefits of this paragraph if it notifies the Department within five (5) working days by telephone and within ten (10) working days in writing of the date it becomes aware or reasonably should have become aware of the event impeding performance. The written submission shall include all necessary documentation, as well as a notarized affidavit from an authorized individual specifying the reasons for the delay, the expected duration of the delay, and the efforts which have been made and are being made by FirstEnergy to mitigate the effects of the event and to minimize the length of the delay. The initial written submission may be supplemented within 10 working days of its submission. FirstEnergy's failure to comply with the requirements of this paragraph specifically and in a timely fashion shall render this paragraph null and of no effect as to the particular incident involved.

c. The Department will decide whether to grant all or part of the extension requested on the basis of all documentation submitted by FirstEnergy and other information available to the Department. In any subsequent litigation, the operator shall have the burden of proving that the Department's refusal to grant the requested extension was an abuse of discretion based upon the information then available to it.

13. Severability. The paragraphs of this Consent Order and Agreement shall be severable and should any part hereof be declared invalid or unenforceable, the remainder shall continue in full force and effect between the parties.

14. Entire Agreement. This Consent Order and Agreement shall constitute the entire integrated agreement of the parties. No prior or contemporaneous communications or prior drafts shall be relevant or admissible for purposes of determining the meaning or intent of any provisions herein in any litigation or any other proceeding.

15. Attorney Fees. The parties shall bear their respective attorney fees, expenses and other costs in the prosecution or defense of this matter or any related matters, arising prior to execution of this Consent Order and Agreement.

16. Modifications. No changes, additions, modifications, or amendments of this Consent Order and Agreement shall be effective unless they are set out in writing and signed by the parties hereto.

17. Titles. A title used at the beginning of any paragraph of this Consent Order and Agreement may be used to aid in the construction of that paragraph, but shall not be treated as controlling.

18. Decisions under Consent Order. Except as provided in Paragraphs 8, above, any decision which the Department makes under the provisions of this Consent Order and Agreement is intended to be neither a final action under 25 Pa. Code § 1021.2, nor an Adjudication under 2 Pa. C.S. § 101. Any objection in which FirstEnergy may have to the decision will be preserved until the Department enforces this Consent Order and Agreement.

19. Counterparts. This Consent Order and Agreement may be executed in multiple counterparts, each of which shall be deemed an original agreement, and all of which shall constitute one agreement between the parties. The parties authorize execution by signatures transmitted via facsimile or .pdf format.

20. Termination Clause. The provisions of this Consent Order and Agreement shall expire on December 15, 2009 or upon the Department's issuance of an alternate opacity standard, whichever occurs first.

IN WITNESS WHEREOF, the parties hereto have caused this Consent Order and Agreement to be executed by their duly authorized representatives. The undersigned representatives of FirstEnergy certify under penalty of law, as provided by 18 Pa. C.S. § 4904, that they are authorized to execute this Consent Order and Agreement on behalf of FirstEnergy; that FirstEnergy consents to the entry of this Consent Order and Agreement as a final ORDER of the Department; and that FirstEnergy hereby knowingly waives its rights to appeal this Consent Order and Agreement and to challenge its content or validity, which rights may be available under Section 4 of the Environmental Hearing Board Act, the Act of July 13, 1988, P.L. 530, No. 1988-94, 35 P.S. § 7514; the Administrative Agency Law, 2 Pa. C.S. § 103(a) and Chapters 5A and 7A; or any other provision of law. [Signature by FirstEnergy's attorney certifies only that the agreement has been signed after consulting with counsel. If FirstEnergy chooses not to consult with counsel before signing, please initial and write the word "waived" on the attorney signature block.]

FOR FIRSTENERGY
GENERATION CORP:

Print Name: FRANK A. LUBICH
President or Vice President

James F. Pearson
Print Name: JAMES F. PEARSON
Secretary or Treasurer

Chester R. Babst III
Chester R. Babst, III
Attorney for FirstEnergy

FOR THE COMMONWEALTH OF
PENNSYLVANIA, DEPARTMENT OF
ENVIRONMENTAL PROTECTION:

Mark A. Wayner
Air Quality Program Manager

Michael J. Heilman
Assistant Regional Counsel