

**BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**

An Operating Permit for the Valley Power Plant,
Milwaukee County, Wisconsin.

Source I.D. 241007800

Permit No. 241007800-P20

Proposed by the Wisconsin Department of
Natural Resources on December 22, 2010.

Petition No. V-2011-_____

PETITION REQUESTING THAT THE ADMINISTRATOR OBJECT TO ISSUANCE OF THE
PROPOSED TITLE V OPERATING PERMIT FOR THE VALLEY POWER PLANT

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Pursuant to Clean Air Act § 505(b)(2) and 40 CFR § 70.8(d), the Sierra Club and Clean Wisconsin hereby petition the Administrator (“the Administrator”) of the United States Environmental Protection Agency (“U.S. EPA” or “EPA”) to object to a proposed Title V Operating Permit for the Valley Power Plant (“Edgewater”), Permit Number 241007800-P20 (“Permit”). The Permit was proposed to U.S. EPA by the Wisconsin Department of Natural Resources (“DNR”) more than 45 days ago. A copy of the proposed Permit is attached as Exhibit 1.

Sierra Club and Clean Wisconsin provided comments to the DNR on the draft permit and the revised draft permit. A true and accurate copy of Clean Wisconsin and Sierra Club’s joint comments is attached at Exhibit 2. Additionally, the American Civil Liberties Union, Black Health Coalition of Wisconsin, Inc., Midwest Environmental Advocates, and Milwaukee Latino Health Coalition (hereinafter collectively as “ACLU”), as well as many other members of the public, also commented on the permit during the public comment period, including at a public hearing conducted in Milwaukee, Wisconsin. A copy of ACLU’s written comments is attached as Exhibit 3. DNR’s response to Sierra Club and Clean Wisconsin’s comments is attached as Exhibit 4. DNR’s response to other public comments is attached as Exhibit 5. U.S. EPA also commented to DNR during the comment period. DNR’s response to EPA’s comments, and DNR’s supplemental response to those comments, are attached as Exhibits 6 and 7, respectively.

This petition is filed within sixty days following the end of U.S. EPA's 45-day review period, as required by Clean Air Act ("CAA") § 505(b)(2).¹ The Administrator must grant or deny this petition within sixty days after it is filed. If the Administrator determines that the Permit does not comply with the requirements of the CAA, or fails to include any "applicable requirement," she must object to issuance of the permit. 42 U.S.C. § 7661b(b); 40 C.F.R. § 70.8(c)(1) ("The [U.S. EPA] Administrator will object to the issuance of any permit determined by the Administrator not to be in compliance with applicable requirements or requirements of this part."). "Applicable requirements" include, *inter alia*, any provision of the Wisconsin State Implementation Plan ("SIP"), including any term or condition of any preconstruction permit, any standard or requirement under Clean Air Act sections 111, 112, 114(a)(3), or 504, acid rain program requirements. 40 C.F.R. § 70.2.

This petition seeks an objection by the Administrator for two reasons:

- 1) The particulate matter monitoring in the permit is deficient.
- 2) The permit omits applicable emission limits that are applicable to the Valley Power plant.

¹ DNR proposed the permit to EPA on December 22, 2010. EPA's forty-five (45) comment period expired no early than February 5, 2011. The public's time for petitioning the Administrator extends through, at least, April 6, 2011. DNR issued the final permit on February 24, 2011.

I. THE PERMIT LACKS SUFFICIENT PARTICULATE MATTER MONITORING AND DNR HAS NOT PROVIDED SUFFICIENT EXPLANATION FOR THE PERMIT'S MONITORING.

The Valley Power Plant permit at issue here continues a disturbing pattern of flagrant disregard of the Clean Air Act by the Wisconsin DNR. DNR acknowledges that the permit it issued lacks sufficient monitoring and a sufficient permit record to justify the Permit's monitoring requirements, yet issues the permit anyway. The Permit suffers the same deficiencies related to monitoring that have been the basis for prior Administrator objections. As set forth below, the Administrator must object to the Valley permit for the same reasons that the Administrator has objected to numerous similarly-deficient Wisconsin permits. Additionally, because the Wisconsin DNR appears unable or unwilling to comply with the basic requirements of 40 C.F.R. part 70, the Administrator should implement sanctions and revoke the state's authority to issue Clean Air Act operating permits. *See* 40 C.F.R. § 70.10(b), (c)(1)(ii)(B).

Title V and its implementing regulations require DNR to include in the permit "terms, test methods, units, averaging periods and other statistical conventions consistent with the applicable requirement," for the relevant time period, that are sufficient to assure compliance. 40 C.F.R. § 70.6(a)(3)(B), (c); Wis. Admin. Code § NR 407.09(1)(c)1.b., NR 407.09(4)(a)1. (all operating permits shall contain compliance requirements "sufficient to assure compliance with the terms and conditions of the permit"); *Sierra Club v. EPA*, 536 F.3d 673, 675 (D.C.Cir. 2008) ("[w]here the applicable requirement does not require periodic testing,' subsection 70.6(a)(3)(B) obliges the permitting authority to add to 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.""); *In re Fort James Camas Mill*, Petition No. X-1999-1 (Dec. 22, 2000); *In re PacifiCorp's Jim Bridger and Naughton Electric Utility Steam Generating Plants*, Petition No. VIII-00-1 (Nov. 16, 2000).

EPA recently objected to multiple Title V permits issued by Wisconsin DNR that suffered the same unexplained and faulty reliance on parameter monitoring that DNR included in the permit for Valley. *In re Alliant Energy- WPL Edgewater Generating Station*, Order at 7-10 (EPA Adm'r Aug. 10, 2010); *In re Wisconsin Public Service Corp.'s JP Pulliam Power Plant*, Order at 8-13 (EPA Adm'r June 28, 2010); *In re We Energies Oak Creek Power Plant*, Order at 15-16 (EPA Adm'r June 13, 2009); *In re Wis. Dept. Admin. UW-Madison Walnut Street Heating Plant*, Order at 7 (EPA Adm'r Nov. 5, 2007); *accord Sierra Club v. EPA*, 536 F.3d 673 (D.C. Cir. 2008); *In re Citgo Refining and Chemicals Co. L.P., West Plant*, Order at 7 (EPA Adm'r May 29, 2009); U.S. EPA Region 4 Objection Proposed Part 70 Operating Permit International Paper- Vicksburg Mill Permit no. 2780-00015 (Dec. 1999) (hereinafter "IP-Vicksburg")(finding that a Title V permit must "include a periodic monitoring scheme that will provide data which is representative of the source's actual performance."). The Administrator's decisions in those prior objections, as well as 40 C.F.R. §§ 70.6(a)(3)(i)(A), (B), 70.6(c), require, at a minimum, the following:

- 1) That the monitoring required by the permit be sufficient to yield reliable data from the relevant time period to assure the source is in continuous compliance with all applicable limits and requirements;
- 2) a full explanation and basis in the record for the monitoring methods and requirements in the permit;

- 3) that where parametric monitoring is used to supplement infrequent stack testing to ensure continuous compliance, an on-the-record correlation must be made between the parameter(s) used and the emission rate; and
- 4) where parametric monitoring is used, the permit must establish the indicator range(s) that correspond to compliance and non-compliance with the underlying limit.

A. The Permit Contains Insufficient Monitoring for The Boilers

The Permit purports to require components of particulate matter monitoring for the Valley plant boilers. First, the permittee is required to conduct periodic stack tests. Permit § I.A.1.b.(4)(a), (7). Second, although extremely vague, the Permit appears to rely on parametric monitoring by monitoring the pressure drop across each baghouse that controls the boilers once every eight hours, and requires the baghouse to be maintained at 0.25 inches of water column and a minimum of 25% boiler air flow. Permit § I.A.1.b.(2), c.(4). Third, separately from the monitoring requirements in the section of the permit specific to the particulate matter emissions from the boiler, the Permit also requires continuous emission monitoring systems (CEMs) on at least one of the Valley units. Permit § IV.5, 6. Specifically, a particulate matter CEMs is required on Valley Unit 1 and a specific correlation curve between particulates and opacity is required for Valley Unit 2 so that the opacity monitor can be used to monitor particulates. *Id.*²

² There appears to be a disagreement about what the monitoring requirements are. The Consent Decree and section IV.6 of the Permit clearly distinguishes between particulate matter CEMs and continuous opacity monitoring. The Consent Decree and Permit require the CEM to monitor particle mass and to convert the result into pounds per million Btu heat input. Permit § IV.6.a. Yet the permittee contends that its opacity monitoring systems is the particulate matter CEMs. *See* Ex. 6 at 3. If the facility has not installed a CEM that measures mass of particulate matter and converts that mass into lb/MMBtu, which the opacity monitors do not appear from the permit record to do, the facility is in violation of both the Consent Decree and the Permit.

This monitoring is insufficient for several reasons. First, the PM CEMS are the most specific and accurate continuous monitoring option—more so than parametric monitoring of baghouse pressure drop—but is buried in the back of the permit, instead of in the monitoring section associated with the applicable PM limits in section I. There is also considerable confusion in the permit record regarding the PM CEMS. The permittee contends that it will not use the CEMS for compliance demonstration purposes. *See Ex. 6 at 3.* Yet, in a cryptic statement, the Wisconsin DNR asserts that it “is not limiting the use of this [CEMS] data to determine non-compliance pursuant to the credible evidence rule.” *Id.* This apparent disagreement between the facility and DNR regarding what the continuous monitoring requirements in the permit are, and what monitoring is to be used to determine permit compliance, highlights the need for adequate monitoring to be included in the permit and for the permit to be clarified.

Second, to the extent that the continuous opacity monitors are being used as a surrogate monitoring method, the permit does not establish the correlation between opacity emission rates and PM emission rates. That correlation must be set forth in the permit. *See In re Midwest Generating, LLC Waukegan Generating Station*, Order at 20 (EPA Adm’r Sept. 22, 2005) (objecting to a permit that relied upon opacity as a surrogate for PM monitoring but failed to “include details on how the opacity monitoring... indicate[s] compliance with the emission limitations. The permit must include a correlation between these measurements and compliance with the PM emission limitations.”) As the Administrator previously determined, where opacity is used as the surrogate method to assure compliance with PM limits, “the title V permit must include a specific opacity limit or

a method for determining an opacity limit that would correlate the results of the PM testing results and the opacity limit.” *Id.* Moreover, to the extent that the applicant contends that its existing continuous opacity monitors satisfy the requirement for PM CEMS, there is nothing in the record indicating how the opacity values are translated into pounds of particulate matter per million Btu, as required by the Permit and the Consent Decree. Permit § IV.6.a.; *U.S. v. Wis. Elec. Power Co.*, Case No. 03-CV-371, Am. Consent Decree at ¶ 94.

Third, the permit record contains no apparent basis for the baghouse pressure drop parameter monitoring approach used by DNR. Specifically, while the PM limits in the permit apply at all times, and the 0.15 lb/MMBtu limits are instantaneous (no averaging period), Permit § I.A.1.a.(1), the permit only requires monitoring of baghouse pressure drop once every eight hours. *Id.* § I.A.1.c.(4). Adequate monitoring, or “compliance demonstration,” in the permit must be sufficient such that the data collected and recorded can be used to demonstrate compliance or non-compliance with the underlying limit. This incorporates both a quantitative element (emission rate) and a temporal element. The temporal element requires the monitoring to correspond to the averaging period for the emission limit. Here, DNR offers no basis for a conclusion that monitoring once every eight hours is sufficient to ensure compliance with an instantaneous limit.

The permit record also lacks a basis for the pressure drop range established in the permit (0.25 inches of water column). *Id.* § I.A.1.b.(2). A parameter range must be set based on the range established during a compliance stack test, or the range that resembles optimum operation of the device. *E.g., Waukegan Order*, *supra*, at 21 (stating that for ESP parametric monitoring, the permit should set the range based on the range recorded

during compliance testing or that represents optimum operation).³ EPA has specifically stated that:

In order to make the parametric monitoring conditions enforceable, a correlation needs to be developed between the control equipment parameter(s) to be monitored and the pollutant emission levels. The source needs to provide an adequate demonstration (historical data, performance test, etc.) to support the approach used. In addition, an acceptable performance range for each parameter that is to be monitored should be established.

In the Matter of Tampa Electric Co., F.J. Gannon Station, Objection to Proposed Part 70 Operating Permit No. 0570040-002-AV (Sept. 8, 2000); see also In the Matter of the Huntley Generating Station, Order Objecting to Operating Permit No. II-2002-01 at 21-22 (July 31, 2003) (same). DNR does not explain how a pressure drop of 0.25 inches of water column or greater ensures compliance with the applicable limits in the permit and, if it does, what the basis is for such a conclusion.

In response to EPA's comments on the draft permit, DNR indicates that the baghouses achieve 99.91% control efficiency and that the baghouses "have to be operated and maintained according to the manufacturer's specifications..." Ex. 6 at 5. However, these bare assertions do not make the necessary connection. It appears that DNR may be assuming: (1) that the baghouses, if operated according to manufacturer's specifications, will always achieve 99.91% control of particulate; (2) that 99.91% control will ensure continuous compliance with the permit limits regardless of fuel quality and particulate loading to the baghouse; and (3) that 0.25 inches of water column pressure drop is all that

³ This issue was raised in comments. See Comments of Sierra Club and Clean Wisconsin at pp. 2-6; Comments of ACLU at 3.

is necessary to meet the manufacturer's specifications. These assumptions are not explicit in the permit record, nor are the underlying facts to support them. At a minimum, DNR needs to make these assumptions and their factual bases explicit in the permit record. Furthermore, if the "manufacturer's specifications" are anything in addition to a 0.25 inch pressure drop (such as bag type, maximum or minimum air flow, temperature, etc.), they must be included in the permit record, subject to public notice and comment, and subject to adequate monitoring and recordkeeping to ensure that each specification is being complied with at all times.

Moreover, while part of the Compliance Assurance Monitoring (CAM) plan, which is a different requirement from the monitoring required by 40 C.F.R. § 70.6(a)(3)(B), (c) and Wis. Admin. Code § NR 407.09(1)(c)1.b., NR 407.09(4)(a)1., there is similarly no apparent basis for the conclusion in Permit § V.A. and B.a.(1) that 10% opacity from the boilers is correlated to PM and PM10 emission rates that comply with the applicable limits, nor any basis for using an opacity rate averaged over a three hour block average to determine compliance with permit limits that are expressed as instantaneous (i.e., not based on a 3-hour block). *See* Permit § I.A.1.a.(1) and (2).

As it has done for similar failures by DNR in prior permits, the EPA should object here because "it is not clear from the permit or the permit record how this monitoring scheme will ensure compliance." *Oak Creek Power Plant*, *supra*, at 15.

B. The Permit Contains Insufficient Monitoring for Coal and Flyash Handling.

Deficient PM monitoring is not limited to the boilers. The Permit lacks sufficient monitoring for the limits in sections I.B.1.a.(1), I.B.2.a.(1), I.C.1.a.(1), I.C.2.a.(1), I.D.1.a.(1), I.D.3.a.(2). For example, there is a 20% opacity standard that applies to “Coal Handling Operations.” Permit § I.B.2.a.(1). The monitoring requirement associated with that limit merely cross-references vague work practices. § I.B.2.b. However there is no basis in the permit record for the implicit conclusion that the work practices ensure compliance with the 20% opacity limit. Moreover, it appears that visible emission testing has never even been done, so there is no basis for a determination (if any was even made) that the work practices ensure compliance with the limit. *See* Ex. 6 at 4 (“the language in the permit is *believed to... keep opacity from the coal stockpile below 20%... There are no method 9 opacity evaluations in our files- either done by us or submitted by the company.*” (emphasis added).)

Similarly, the Flyash Handling system is subject to a particulate matter emission limit of 0.20 pounds per 1000 pounds of gas. *Id.* § I.C.1.a.(1). However, there is no monitoring required. Instead, the permit provides the test methods that would apply *if* compliance testing was required. § I.C.1.c.(1). Yet compliance testing is not required. The permit also requires daily observations, § I.C.1.b.(2), but there is no basis for a connection between those observations and any emission rate. There is no method identified (nor any conceivable method) for determining the mass emission rate in pounds of particulate per 1000 pounds of exhaust gas by simply “observing” the process. In short, there is effectively

no monitoring to ensure continuous compliance with the 0.20 lbs PM/1000 lbs of gas limit.⁴

Furthermore, there is no monitoring in the permit for several permit requirements.

These include the following:

- a) There is no monitoring or recordkeeping to determine when coal begins to be combusted and when coal combustion ceases, which are necessary to determine when the limit in § I.A.1.a.(2) applies and, therefore, whether the facility is in compliance.
- b) There is no monitoring or recordkeeping to determine when the boiler operations are “normal,” which is necessary to determine when the requirements in § I.A.1.b.(2) apply and, therefore, whether the facility is in compliance.
- c) There is no monitoring or recordkeeping to determine what the boiler emissions are when the pressure drop requirement in § I.A.1.b.(2) is not applicable (i.e., how emissions are monitored during non-normal operations).
- d) There is no monitoring or recordkeeping to determine when a new fire is being started or combustion equipment is being cleaned, which is necessary to determine compliance with § I.A.2.a.(1).
- e) There is no monitoring or recordkeeping to determine whether the heat release is equal to or greater than 17,000 Btu per cubic feet per hour, which is necessary to determine whether the plant is complying with § I.A.5.a.(1)(b).
- f) There is no monitoring or recordkeeping to determine whether the emissions from the coal handling operations are exceeding 0.20 pounds of particulates per 1000 pounds of gas, which is necessary to determine compliance with § I.B.1.a.(1).

⁴ As set forth below, the 0.20 lb PM/1000 lb of gas limit also applies to the Coal Handling operations. When DNR revises the permit following the Administrator’s objection for failure to include that limit, DNR must also include sufficient monitoring.

- g) There is no monitoring or recordkeeping to determine whether each of the requirements in § I.B.1.a.(2) is being met.
- h) There is no monitoring or recordkeeping to determine whether the requirements in § I.D.4.a.(1)a-c have been complied with.

A title V permit must contain sufficient monitoring to assure compliance with each of the terms and conditions of the permit. 40 C.F.R. §§ 70.6(a)(3)(i), 70.6(c)(1). The permit record must also specifically document the rationale for the monitoring in the permit. 40 C.F.R. § 70.7(a)(5). The Administrator should object, once again, to Wisconsin DNR's failure to include sufficient monitoring in the permit for these emission sources, to explain the basis for the inadequate (or missing) monitoring for these emission points, and for DNR's failure to respond to specific public comments on this issue. *See Edgewater Generating Station, supra*, at 10.

C. The Wisconsin DNR's Response to Comments Is Deficient And Acknowledges The Permit's Deficiencies Yet Fails to Correct Them.

DNR's response to comments recognizes that the Permit's monitoring requirements are the same monitoring requirements that have been objected to by the EPA Administrator in prior orders. Ex. 4 at 2. Nevertheless, DNR says that it is retaining the insufficient monitoring provisions of this permit and, maybe, eventually, after the conclusion of a now four-year-old "review" process, the DNR may someday change the Permit's monitoring conditions. *Id.* This is unlawful. If, as DNR acknowledges, the permit does not contain sufficient monitoring, it must revise the permit to contain sufficient monitoring before it is issued. It cannot shirk this obligation by punting to a possible permit revision at some unspecified future event.

The DNR must establish monitoring *in the permit*, and provide a sufficient explanation for that monitoring *in the Statement of Basis*. 42 U.S.C. § 7661c(c); 40 C.F.R. § 70.6(c)(1); *Sierra Club v. EPA*, 536 F.3d 673, 675 (D.C.Cir. 2008) (“[w]here the applicable requirement does not require periodic testing,’ subsection 70.6(a)(3)(B) obliges the permitting authority to add to 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.’”); *In re Fort James Camas Mill*, Petition No. X-1999-1 (Dec. 22, 2000); *In re PacifiCorp’s Jim Bridger and Naughton Electric Utility Steam Generating Plants*, Petition No. VIII-00-1 (Nov. 16, 2000). Moreover, the public and EPA have a right to review and comment on the monitoring scheme as a part of the Title V permit. DNR’s attempt to defer determinations of monitoring and compliance demonstration to some unknown future date is unlawful. *See Edgewater Generating Station*, *supra*, at 8 (rejecting the DNR’s prior attempt to avoid addressing this issue).

For each of these reasons, the Administrator must object to the deficient permit monitoring provisions, the missing monitoring provisions, the lack of a sufficient explanation of rationale for monitoring requirements, and the failure to sufficiently respond to comments. 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(c)(1).

D. The DNR Improperly Included Erroneous Comments In The Compliance Assurance Monitoring Section of the Permit.

The DNR included language in section VI of the Preliminary Determination at the permittee’s request that further exacerbate the confusion DNR has causes regarding monitoring requirements. At the behest of the applicant, DNR included comments in section VI.H. of the Preliminary Determination that says that PM CEMS have not been

certified by EPA, that they are “not currently used to verify compliance.” See Final Addendum Memo at 2. The purpose of this change is unclear, but it adds to the overall confusion related to particulate monitoring.

To the extent the applicant attempts to create a defense to particulate matter emission limit violations by creating a vague statement in the permit record about the use of CEMS, DNR erred by modifying the record. First, EPA has approved particulate matter CEMS. It has established Performance Standards (PS) 11⁵ and 12 for those monitors. Second, the DNR cannot limit the use of credible evidence, including the use of particulate matter CEMS, in determining compliance or non compliance with the permit limits. The U.S. EPA and citizen suit litigants have the authority to bring enforcement actions “on the basis of *any information available* to the Administrator.” 42 U.S.C. § 7413 (emphasis added). This has been interpreted to mean any “credible evidence” that a court would accept. *Sierra Club v. Pub. Serv. Co. of Colorado, Inc.*, 894 F.Supp. 1455 (D.Colo. 1995) (neither CAA nor its implementing regulations limit the evidence of compliance or noncompliance to the methods set forth in a permit); *Credible Evidence Revisions*, 62 Fed. Reg. 8314 (Feb. 24, 1997); U.S. EPA Region 9 *Title V Permit Review Guidelines*, Sept. 9 1999, p. III-46.

While DNR’s act of making after-the-fact changes to the Preliminary Determination has no legal effect, DNR is wrong to create confusion. In addition to objecting to the deficient particulate matter monitoring for the reasons set forth above, the Administrator should direct the DNR to clarify that the particulate matter CEMS have been approved by

⁵ See <http://www.epa.gov/ttn/emc/perfspec.html>

EPA, and even if they had not, would nevertheless constitute credible evidence and that the Permit and permit record do not limit the use of credible evidence.

II. THE DNR IMPROPERLY REMOVED A PARTICULATE MATTER EMISSION LIMIT FROM THE DRAFT PERMIT.

In its response to EPA's comments, DNR indicates that "it was an error to include the 0.20 lb/1000 lb emission limit in the permit" for the coal handling system. Ex. 6 at 5. The limit has been removed from the Final Permit. This was in error and the Administrator must object because the limit is an applicable requirement that must be included in the permit.

The Draft Permit included that limit in permit section I.B.1.a.(1) and cited Wis. Admin. Code § NR 415.05(1)(m) as the basis. *See* Draft Permit, attached as Exhibit 8. The SIP provision, NR 415.05(1)(m), applies to "[g]rinding, drying, mixing, conveying, sizing or blending..." The coal handling system contains both crushing houses and conveyors and, therefore, the limit clearly applies. *See e.g.*, Ex. 6 at 1; Preliminary Determination at 4, attached as Exhibit 9. There is no exclusion in Wis. Admin. Code § NR 415.05 for the coal conveying process at the plant. Specifically, contrary to DNR's apparent belief that the provision excludes "fugitive" emissions, Ex. 6 at 5, there is no such exclusion. Nor, even if it did, are the emissions from the coal handling process all fugitive. DNR's removal of the applicable requirement from the permit is in error and an objection is required.⁶

⁶ This issue arises because of the limit's removal from the Draft Permit. Since the limit was in the Draft and there was no indication that DNR would remove it from the Final Permit, commenting on the removal was not practical and no comments were required to preserve this issue for review. 42 U.S.C. § 7661d(b)(2) (comment not required where "it was impractical to raise... or unless the grounds for such objection arose after" the comment period); 40 C.F.R. § 70.8(d) (same).

III. THE PERMIT FAILS TO INCLUDE APPLICABLE REQUIREMENTS FROM THE ACT'S PSD PROGRAM THAT WERE TRIGGERED BY PRIOR MODIFICATIONS

Title V requires that certain air emission sources, including major stationary sources, apply for and obtain an operating permit that includes all "enforceable emission limitations and standards" and "such other conditions as are necessary to assure compliance with application requirements" of the Clean Air Act. 42 U.S.C. §§ 7661a(a), 7661c(a)-(b); *see also* Wis. Admin. Code § NR 407.09(1). "Applicable requirements" are defined to include "(1) any standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under title I of the Act...." 40 C.F.R. § 70.2; *see also* Wis. Admin. Code § NR 400.02(26).

A. The Permit Lacks Applicable PSD Program Requirements.

Among the requirements that must be included in a Title V permit are the requirements of the PSD program, such as best available control technology, and the requirement to demonstrate protection of air quality standards and increments. *See e.g.*, 42 U.S.C. §§ 7470, *et seq.*; 40 C.F.R. §§ 51.160-51.166, 52.21; Wis. Admin. Code §§ NR 405.08, *et seq.*; *In re Wis. Power & Light Columbia Gen. Station*, Objection Order (U.S. EPA Adm'r, Oct. 9, 2009); *In re Monroe Elec. Gen. Plant Entergy Louisiana*, Objection Order at 2 (U.S. EPA Adm'r, June 11, 1999); *In re Roosevelt Regional Landfill*, Objection Order at 8-9, 13 (U.S. EPA Adm'r, May 4, 1999).

The Wisconsin SIP contains, and at all relevant times hereto contained, provisions implementing the Clean Air Act's Prevention of Significant Deterioration (PSD) Program. Different regulations were adopted and applied at different times pursuant to the Wisconsin SIP. On June 19, 1978, EPA approved the Federal PSD program, 40 CFR 52.21

(b) through (v), into the Wisconsin SIP at 40 C.F.R. § 52.2581 because Wisconsin had not submitted an approvable PSD program. 43 Fed. Reg. 26,410. On May 27, 1999, EPA promulgated a final rule adopting Wisconsin's PSD program in Wis. Admin. Code ch. NR 405 in place of the federal rules in 40 C.F.R. § 52.21. 64 Fed. Reg. 28,745 (May 27, 1999). That rulemaking was effective on June 28, 1999. *Id.* On December 17, 2008, EPA promulgated a rule accepting certain revisions to the Wisconsin PSD program. 73 Fed. Reg. 76,560 (December 17, 2008). Those revisions were effective January 16, 2009. *Id.*⁷

Under the Clean Air Act's PSD program and Wisconsin's SIP, a new major source of air pollution cannot be constructed, and an existing major source of air pollution cannot undergo a "major modification," without a permit. *See* 42 U.S.C. §§ 7475(a) (prohibiting the construction of a major emitting facility without PSD review, issuance of a PSD permit, and imposition of BACT limits), 7479(2)(C) ("construction" includes the "modification" of a source or facility); 40 C.F.R. § 52.21; Wis. Admin. Code §§ NR 405.07(1) (prohibiting the construction or major modification of a major stationary source without PSD review and permitting), NR 405.08 (requiring best available control technology for any new or modified source). Once a major modification occurs, numerous requirements apply to the modified facility, including but not limited to, best available control technology, emission impact demonstrations, monitoring, and other requirements. *See e.g., Sierra Club v. Dairyland Power Cooperative*, Case No. 10-cv-303-bbc, 2010 U.S. Dist. LEXIS 112817, * 12

⁷ Sierra Club and Natural Resources Defense Council filed a petition for judicial review of EPA's December 17, 2008, action within the time provided by the Clean Air Act. If the Seventh Circuit reverses and/or remands the December 2008 EPA action, the 1999 version of Wis. Admin. Code ch. NR 405 will apply.

(W.D.Wis. Oct. 22, 2010) (“In addition to the requirement that the source obtain a preconstruction permit... the proposed facility must, among other requirements, be subject to best available control technology... and demonstrate that the emissions increases resulting from its modifications will not threaten the area's attainment status... [these] individual requirements... are not subsumed by the initial requirement to obtain a preconstruction permit.” (internal cites and quotations omitted)); *see also* Wis. Admin. Code § NR 405.16(1) (approval to construct does not relieve operator of requirement to comply with requirements, including BACT in NR 405.08).

For the purpose of determining whether a “major modification” occurs, and therefore, when these applicable requirements apply, the regulations define a “major modification” as “any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase” of a regulated air contaminant. 40 C.F.R. § 52.21; Wis. Admin. Code § NR 405.02(21). Pursuant to the PSD regulations applicable to pollution sources in Wisconsin for projects occurring prior to January 16, 2009, emissions increases are measured as the difference between the annual average emissions during the 24 months prior to the project and the plant’s post-project “actual emissions.” 40 C.F.R. § 52.21(b)(2), (3)(i), and (21) (1993); Wis. Admin. Code §§ NR 405.02(1), 405.02(24)(a) (1999). Post-project “actual emissions” are the emission source’s potential to emit unless the source: (1) is an electric utility steam generating unit (EUSGU); (2) that meets certain monitoring and reporting requirements. 40 C.F.R. § 52.21(b)(21) (1993); Wis. Admin. Code § NR 405.02 (1) (1999).

Prior to January 16, 2009, an EUSGU⁸ could determine emission increases by comparing its pre-project annual “actual emissions” to its “representative actual annual emissions... *provided* the source owner or operator maintains and submits to the department, on an annual basis for a period of 5 years from the date the unit resumes regular operation, information demonstrating that the physical or operational change did not result in an emissions increase.” Wis. Admin. Code § NR 405.02(1)(d) (1999) (emphasis added); 40 C.F.R. § 52.21(b)(21)(v) (1993). This alternative “actual-to-projected-actual” test, however, is conditional and only applies when the owner or operator complies with the monitoring and reporting requirements.

1. The Valley Plant Underwent Several Physical Changes and Changes in Method of Operation Which Triggered PSD “Applicable Requirements.”

a) The Valley Plant Boilers Underwent Physical Changes That Triggered Applicable PSD Requirements.

The definition of major modification—and therefore application of the PSD program—applies to physical changes. The PSD program applies to *every* physical change, without limitation. *New York v. Env'tl. Protection Agency*, 443 F.3d 880, 886 (D.C.Cir. 2006) (holding that PSD applies to every physical change, not merely to “physical changes exceeding a certain magnitude.” (citing *Ala. Power*, 636 F.2d at 400)) (hereinafter “New York II”). This includes even “the most trivial activities—the replacement of leaky pipes, for example...” *WEPCO*, 893 F.2d at 905, *id.* at 908-09 (“any physical change means

⁸ The Valley power plant units are EUSGUs because they are “constructed for the purpose of supplying more than one third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale.” 40 C.F.R. §52.21(b)(31); Wis. Admin. Code § NR 405.02(11m).

precisely that.”); *see also New York II*, 443 F.3d at 885-87 (Congress’ use of the phrase “any physical change” was intended to apply to the broadest possible category of changes); *New York I*, 413 F.3d at 40-42; *United States v. Cinergy Corp.*, 495 F. Supp. 2d 892, 901 (S.D. Ind. 2007) (“The CAA defines the term ‘modification’ broadly as ‘any physical change... which increases the amount of any air pollutant emitted...’” (*citing WEPCO*, 893 F.2d at 905; *Ala. Power Co.*, 636 F.2d at 400)).

The Valley Plant underwent numerous physical changes, including replacement of the primary superheater and economizer in each unit. Fox Report at 2, attached as Exhibit 10; *see also* Wis. Pub. Serv. Commn. Dockets 6630-CE-129, 6630-CE-148, 6630-CE-181, and 6630-CE-227, attached as Exhibit 11. Specifically, the following changes occurred:

- Valley Boiler 1: primary superheater and economizer replaced in May, 1994, at a cost of \$1,377,149. WEPCO Statement in Response to Question 18, Pursuant to 42 U.S.C. § 7414, attached as Exhibit 12; Pub. Serv. Comm’n Docket 6630-CE-227 (Feb. 27, 1996), Exhibit 11, at 1; Ltr. from David K. Porter, WEPCO, to Lynda L. Dorr, PSCW (Feb. 20, 1996), Exhibit 11, at 2; PSCW File 6630-CE-227 Ltr. Order (June 17, 1993), Exhibit 11, at 11-12.
- Valley Boiler 2: primary superheater and economizer replaced in June, 1991. WEPCO Statement in Response to Question 18, Pursuant to 42 U.S.C. § 7414, Exhibit 12; Memorandum from Susan Stratton, PSCW, to Commissioners (June 11, 1993), Exhibit 11 at 6; Ltr. from David K. Porter, WEPCO, to Lynda L. Dorr, PSCW (May 3, 1993), Exhibit 11 at 14.
- Valley Boiler 3: primary superheater and economizer replaced in October, 1987. WEPCO Statement in Response to Question 18, Pursuant to 42 U.S.C. § 7414, Exhibit 12; Memorandum from Susan Stratton, PSCW, to Commissioners (June 11, 1993), Exhibit 11 at 6; Ltr. from David K. Porter, WEPCO, to Lynda L. Dorr, PSCW (May 3, 1993), Exhibit 11 at 14; PSCW File No. 6630-CE-129 Ltr. Order (April 30, 1987), Exhibit 11 at 21.
- Valley Boiler 4: primary superheater and economizer replaced in June, 1989. WEPCO Statement in Response to Question 18, Pursuant to 42 U.S.C. § 7414, Exhibit 12; Memorandum from Susan Stratton, PSCW, to Commissioners (June 11, 1993), Exhibit 11 at 6; Ltr. from David K. Porter, WEPCO, to Lynda L. Dorr, PSCW (May 3,

1993), Exhibit 11 at 14; PSCW File No. 6630-CE-148, Ltr. Order (May 17, 1988), Exhibit 11 at 20.

These tube section replacements were due to internal pitting and cracking that led to increasing tube failures and forced outages. Memorandum from Susan Stratton, PSCW, to Commissioners (June 11, 1993), Exhibit 11 at 6-7; Ltr. from David K. Porter, WEPCO, to Lynda L. Dorr, PSCW (May 3, 1993), Exhibit 11 at 14-15. As part of the tube section replacements, the tubes were redesigned to allow individual tubes to be drained. *Id.* The inability to drain the tubes in their original design had resulted in moisture and oxygen to corrode the tubes during periods of boiler outages. *Id.*

b) The Superheater and Economizer Replacements Are Not Routine Maintenance.

These capital projects were clearly not “routine maintenance repair and replacement,” pursuant to 40 C.F.R. § 52.21(b)(2)(iii)(a). Routine maintenance “occurs regularly, involves no permanent improvements, is typically limited in expense, is usually performed in large plants by inhouse employees, and is treated for accounting purposes as an expense.” *Ohio Edison*, 276 F. Supp. 2d at 834 (citing *WEPCO*, 893 F.2d 901). Non-routine and, therefore nonexempt, projects include “capital improvements which generally involve more expense, are large in scope, often involve outside contractors, involve an increase of value to the unit, are usually not undertaken with regular frequency, and are treated for accounting purposes as capital expenditures on the balance sheet.” *Id.*

As the D.C. Circuit has held, the “Routine Maintenance” exemption is only lawful (if at all), based on a *de minimis* theory of administrative necessity. *Alabama Power Co. v. Costle*, 636 F.2d 323, 360-61, 400 (D.C.Cir. 1979); *see also* 57 Fed. Reg. 32313, 32316-19

(July 21, 1992) (explaining the need for the routine maintenance exemption to avoid PSD “encompass[ing] the most mundane activities at an industrial facility (even the repair or replacement of a single leaky pipe, or a change in the way the pipe is utilized.”); *New York v. EPA*, 443 F.3d 880, 883-84, 888 (D.C.Cir. 2006) (holding that the only possible basis for a Routine Maintenance exemption is a *de minimis* theory); *see also In re Tennessee Valley Authority*, 9 E.A.D. at 392-93 (citing *O’Neil v. Barrow County Bd. of Comm’rs*, 980 F.2d 674 (11th Cir. 1993); *North Haven Bd. of Educ. v. Bell*, 456 U.S. 512 (1982)). In fact, because the routine maintenance exemption conflicts with the literal, plain language used by Congress that applies the PSD program to *any* physical change, the routine maintenance exemption must be limited to the very mundane daily activities that would overwhelm permitting agencies if subjected to permitting. *Cf. WEPCO*, 893 F.2d at 909 (warning that RMRR cannot be interpreted to “open vistas of indefinite immunity from the provisions of ... PSD”); *Ohio Edison*, 276 F. Supp. 2d at 855; *In re TVA*, 9 E.A.D. at 410-11 (rejecting an interpretation of RMRR that would “constitute ‘perpetual immunity’ for existing plants, a result flatly rejected by Congress and the circuit courts in *Alabama Power* and *WEPCO*”). Therefore, EPA’s long-standing interpretation of the definition of PSD-triggering “physical changes,” and the routine maintenance exemption, “is to construe ‘physical change’ very broadly, to cover virtually any significant alteration to an existing plant and to interpret the exclusion related to routine maintenance, repair and replacement narrowly.” *See* Letter from Doug Cole, EPA, to Alan Newman, Washington Dept. of Ecology (November 5, 2001)⁹.

⁹ Available at <http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/20011105.pdf>

Here, the superheater and economizer replacements have none of the hallmarks of a truly routine project.¹⁰ Foremost, only projects that are routine for the specific generating unit at issue are considered Routine Maintenance. *United States v. S. Indiana Gas and Elec. Co.*, 245 F.Supp. 2d 994, 1008 (S.D. Ind. 2003). The projects here occurred only once in the entire life of each unit. See Fox Report at 29, 36, 41, and 47, attached as Exhibit 10.

Contrary to industry advocacy positions, EPA has long interpreted the “frequency” factor in an analysis of routine maintenance to be based on the frequency of a project at a particular unit. See Letter from Robert B. Miller, EPA, to Steven Dunn, Wisconsin DNR at 2 (Jan. 29, 2003) (finding that a tube replacement project is not Routine Maintenance because, inter alia, “this would be the first time in the 35 year life of *the boiler* where all the tubes would be replaced. Moreover, the infrequency of such replacement *at this boiler* supports our understanding that complete boiler tube replacements are not performed on a frequent basis.”) (emphasis added)¹¹; Letter from Winston A. Smith, EPA, to James P. Johnson, Georgia Env’tl. Protection Dept. (January 28, 2002) (finding that frequency did not support a finding of routine maintenance “[b]ased on the information presented to us, the previous owner of the mill never performed the same changes *at the No. 3 Recovery Boiler* during its entire 17-year operating history..”) (emphasis added)¹²; Letter from Doug Cole, EPA, to Alan Newman, Washington Dept. of Ecology at 4 (Nov. 5, 2001) (“EPA is not aware

¹⁰ Routine maintenance “occurs regularly, involves no permanent improvements, is typically limited in expense, is usually performed in large plants by inhouse employees, and is treated for accounting purposes as an expense.” *Ohio Edison*, 276 F. Supp. 2d at 834 (citing *WEPCO*, 893 F.2d 901). Non-routine and, therefore nonexempt, projects include “capital improvements which generally involve more expense, are large in scope, often involve outside contractors, involve an increase of value to the unit, are usually not undertaken with regular frequency, and are treated for accounting purposes as capital expenditures on the balance sheet.” *Id.*

¹¹ Available at <http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/20030129.pdf>

¹² Available at <http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/20020128.pdf>

of [Recovery Furnace Number] 2 undergoing such an extensive boiler tube replacement project since it started up as a recovery furnace in 1980, more than twenty years ago”¹³; Letter from Gregg M. Worley, EPA, to Barry R. Stephens, Tenn. Dept. of Env't. and Conservation at 4 (September 14, 2001) (“Therefore, during the entire 40-year operating history of R-1, a generating bank tube replacement project of the magnitude now proposed has occurred only once.”)¹⁴

Similarly, the Seventh Circuit held that projects that “normally occur once or twice during *a unit's expected life cycle*” are not routine. *WEPCO*, 893 F.2d at 912. In *U.S. v. Southern Indiana Gas and Electric Company*, the District Court also agreed with EPA's interpretation—which it found was reasonable, persuasive, and owed deference—that the RMRR exemption “applies only to activities that are routine for a generating unit. The exemption does not turn on whether the activity is prevalent within the industry as a whole.” 245 F.Supp.2d at 1008; *see also Sierra Club v. Morgan*, 2007 U.S. Dist. LEXIS 82760, *36-37 (W.D. Wis. Nov. 7, 2007) (looking to frequency of replacing a boiler wall to the number of occurrences at the particular unit at issue and at the other boilers in the same plant to conclude that the project was “expected to be performed only once or twice during *the boiler's life cycle*.” (emphasis added)), *id.* at *39 (applying the same analysis to another project that “is expected to occur only 2 maybe 3 times in the life of a boiler” and concluding that the frequency does not support RMRR). The once-in-the-unit's lifetime

¹³ Available at <http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/20011105.pdf>

¹⁴ Available at <http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/pca2001.pdf>.

frequency of the superheater and economizer replacements at the Valley plant demonstrate that they were not routine.

Second, the scope of the projects is much larger than routine maintenance. EPA has long interpreted the Routine Maintenance exemption to exclude replacements of entire components, as occurred here. *See* Letter from Robert B. Miller, EPA, to Steven Dunn, Wisconsin DNR; Letter from Doug Cole, EPA, to Alan Newman, Washington Dept. of Ecology at 3 (finding that replacement of a component, rather than a few tubes, does not support a Routine Maintenance determination); Letter from Gregg M. Worley, EPA, to Barry R. Stephens, Tenn. Dept. of Env't. and Conservation at 4 (same). Outside contractors were used. Request for Proposal, attached as Exhibit 21. There was significant time between the planning and the implementation of the projects, including almost ten years for the superheater/economizer replacement on boiler 1. *See* Fox Report, Exhibit 10 at 26; Memo from S. T. Derenne to R. A. Abdoo (January 29, 1990), attached as Exhibit 13, at W001430; Valley Plant – Boiler 2 Primary Superheater and Economizer Replacement Project, Engineering Report and Project Description (January 26, 1990), attached as Exhibit 14, at W001438-39; EPA Region 5, Request for Information Pursuant to 42 U.S.C. § 7414 (December 11, 2002), attached as Exhibit 15, at 000274; Response to Question 3, attached as Exhibit 22. As such, the superheater and economizer replacements were not Routine Maintenance.

The purpose of the projects is also distinct from routine maintenance. The superheater/economizer replacement projects were expected to fix a long-standing problem with cracking and internal pitting, and therefore result in fewer outages. Exhibit

10 at 27-28, 33-35, 45-47; Exhibit 11 at 6. Such projects that improve the unit are not routine. See *WEPCO*, 893 F.2d at 911-12 (holding that a project that rehabilitates aging units as an alternative to retiring them is not routine); *Cinergy*, 495 F. Supp. 2d at 935 (finding a project non-routine based, in part, on the fact that the purpose was to “improve[] operating efficiency’ with less [sic] potential outages.”); *Ohio Edison*, 276 F. Supp. 2d at 858, 860 (finding a project non-routine that “reduc[ed] forced outages and improv[ed] availability and reliability of the unit(s)”). The projects also improved the design (including the ability to drain the tubes), so they are not routine for that reason also. See *Cinergy*, 495 F. Supp. 2d at 934 (holding that projects which include modifying or replacing numerous parts and redesigned, custom, or “upgraded” parts are not routine).

The projects were also expensive, compared to the cost of typical routine maintenance, which might involve inspections or replacement of a single boiler tube. WEPCO Plant Accounting Division, Capital Versus Expense Advisory (January 8, 1990), attached as Exhibit 16, at W001434; Ex. 22. See e.g., *Sierra Club v. Morgan*, 2007 U.S. Dist. LEXIS 82760, *39 (W.D. Wis. 2007) (finding that a \$ 77,000 cost was not Routine Maintenance), *id.* at *44 (same for a \$90,700 project); Letter from Robert B. Miller, EPA, to Steven Dunn, Wisconsin DNR (finding a project costing \$50,000 not to be routine); Letter from Gregg M. Worley, EPA, to Barry R. Stephens, Tenn. Dept. of Env't. and Conservation at 4 (same) (finding a project costing \$924,500 to be expensive compared to annual maintenance budgets and non-routine); see also *Cinergy*, 495 F.Supp.2d at 938, 942-43, 947 (finding a \$1,490,800 project, a \$856,000 project, and a \$665,000 project not to be routine). Moreover, the projects were categorized as “capital,” approved by management

in the central office, involved outside contractors, and received specific project approval by the Public Service Commission of Wisconsin. Exhibit 10 at 25-48; Exhibit 13, at W001430 Exhibit 16, at W001435; Letter from David Porter, WEPCO, to Linda Dorr, PSCW (March 28, 1995), attached as Exhibit 17, at Ex. 1378-79; WEPCO, Specification for Installation of Primary Superheater and Economizer, Boiler 2 (January 1991), attached as Exhibit 18; WEPCO, Project Requisition Summary (January 24, 1990), attached as Exhibit 19. *See Ohio Edison*, 276 F. Supp. 2d at 834, 859, 862 (holding that such facts indicate non-Routine projects); *In re TVA*, 9 E.A.D. at 481, 484-85, 490-91, 493-94 (same). The superheater/economizer replacements were therefore markedly different and treated differently by the company than small repairs of single tubes. *See* Exhibit 10 at 26; Exhibit 13 at W001430; WEPCO, Technical Specification for Fabrication of the Primary Superheater Assemblies for Valley Power Plant Boiler #2 (March 27, 1990), attached as Exhibit 20, at W001420.

c) The superheater and economizer replacements also increased emissions pursuant to the applicable emission increase tests.

i. The Replacements Should Be Subject To the Actual-to-Potential Test.

Whether a project results in a significant “net emissions increase” is determined by calculating the “increase in actual emissions” based on the different definitions of “actual emissions” for pre-project and post-project periods. 40 C.F.R. § 52.21(b)(3)(i), (21) (1993). Once the increase is calculated, it is compared to the thresholds in 40 C.F.R. § 52.21(b)(23)

to determine if the increase is “significant.”¹⁵ There are two possible methods for calculating emission increases attributable to modifications under the NSR program: (1) actual-to-potential test; and (2) actual-to-representative-actual test.¹⁶ The only other test is the actual-to-allowable test, but it is typically never distinguished from the actual-to-potential, because they are virtually identical.¹⁷

As explained in detail below, originally, only the actual-to-potential test existed. 40 C.F.R. § 52.2(b)(2) (1980-1992). EPA promulgated the alternative, actual-to-projected-actual test in 1992, but established two conditions on the use of that test: (1) the emission unit to which it is applied must be an Electric Utility Steam Generating Unit (“EUSGU”)¹⁸; and (2) any EUSGU using the test must submit “information demonstrating that the

¹⁵ A “significant” net emissions increase means an increase in the rate of emissions that would equal or exceed any of the following rates for the following pollutants: 40 tons per year of NO_x; 40 tons per year of SO₂; 7 tons per year of sulfuric acid mist, 25 tons per year of PM, and 15 tons per year of PM₁₀. 40 C.F.R. § 52.21(b)(23)(i). For pollutants subject to regulation under the Act that are not set forth in 40 C.F.R. § 52.21(b)(23)(i), any increase is significant. 40 C.F.R. § 52.21(b)(23)(ii).

¹⁶ Various names are used for this test, but all refer to the same methodology. *See e.g., New York v. EPA*, 413 F.3d 3, 16, 34 (D.C.Cir. 2005) (referring to the 1992 rule’s “representative actual” test as the “actual-to-projected-actual test”); *see also e.g.,* 57 Fed. Reg. at 32,323-24 (referring to the “representative actual test” variously as an “actual-to-actual,” “future actual projection,” “actual-to-future-actual”) (July 21, 1992); *id.* at 32,317 n.10 (referring to the test applied on remand following the *WEPCO* decision as “actual-to-future-actual”); *U.S. v. Ohio Edison Co.*, 276 F.Supp.2d 829, 865-66 (S.D. Ohio 2003) (describing the “actual to projected future actual” test as the “representative actual” test in § 52.21(b)(21)(v)); Letter from Francis X. Lyons, EPA, to Henry Nickel at 2 (May 23, 2000) (describing the “representative actual” test as a comparison of “baseline emissions and a projection of future emissions...”).

¹⁷ The regulations provide the actual-to-allowable test in 40 C.F.R. § 52.21(b)(21)(iii) (1980-2003) by calculating the difference between the pre-project emissions under § 52.21(b)(21)(ii) and the “allowable” post-project emissions under § 52.21(b)(21)(iii). However, there is no meaningful difference between “potential to emit” under § 52.21(b)(21)(iv) and “allowable” emissions under § 52.21(b)(21)(iii). *Compare* 40 C.F.R. § 52.21(b)(4) (defining potential to emit as the maximum capacity under physical design and operational limitations placed on the source) *with* § 52.21(b)(16) (defining allowable emissions as the maximum rate based on the physical capacity and applicable limits). Both describe the emissions based on enforceable limits and physical constraints. Therefore § 52.21(b)(21)(iii) and (iv) are functionally the same test for purposes of calculating an emission increase.

¹⁸ 40 C.F.R. § 52.21(b)(31) defines an EUSGU as a unit capable of supplying more than one third of its potential electric output capacity and more than 25 megawatts of electricity to a distribution system for sale.

physical or operational change did not result in an emissions increase” to the EPA. 40 C.F.R. § 52.21(b)(21)(v)(1993-2002).

Here, the actual-to-potential test applies because the superheaters were redesigned as part of the replacement project and, therefore, not like-kind replacements under the Seventh Circuit’s *WEPCO* decision. Moreover, after 1992, the actual-to-potential test applies unless an EUSGU meets the post-project reporting obligations for at least five years to demonstrate no emission increase. That did not occur for the superheater/economizer projects so the actual-to-potential test applies to the post-1992 project.

In 1990, the Seventh Circuit issued an opinion rejecting the use of the “actual-to-potential” test for the specific projects in the case before it, which the Seventh Circuit deemed to be “like-kind replacements.” *Wis. Elec. Power Co. v. Reilly*, 893 F.2d 901 (7th Cir. 1990) (“*WEPCO*”). Instead, the *WEPCO* court proposed to apply a projection of future operating hours and emission rate for certain type of projects. The Seventh Circuit noted that its holding applied only to like-kind replacements, which are those that “do[] not ‘change or alter’ the design or nature of the facility.” *Id.* at 908; *see also U.S. v. Murphy Oil USA*, 143 F.Supp.2d 1054, 1103-04 (W.D. Wis. 2001) (holding that the *WEPCO* decision only precludes the actual-to-potential test for “like-kind replacements,” which replace “deteriorated generating systems... with similar new equipment *without changing the original design* of the systems.” (emphasis added)); *U.S. v. Westvaco Corp.*, 2010 U.S. Dist. LEXIS 112222 (D.Md.,

Sept. 1, 2010) (same). Here, the design of the superheater was changed and, therefore, the actual-to-potential test applies.¹⁹

Furthermore, in 1991, EPA proposed a rule change to address and reconcile the Seventh Circuit's *WEPCO* decision and the First Circuit's decision in *Puerto Rican Cement*, 889 F.2d 292, which upheld the actual-to-potential test. The resulting rule, known as the "WEPCO Rule," was intended to clarify when the original "actual-to-potential" test would apply and when the new "actual-to-projected-actual" test would apply. 56 Fed. Reg. at 27,630-33. Under the rule, EPA allowed the "actual- to-projected-actual" test for all EUSGUs, regardless of whether the change fit the Seventh Circuit's judicially-created "like kind" category. 57 Fed. Reg. 32,314, 32,317 (July 21, 1992). Critically, the WEPCO Rule required certain monitoring and reporting obligations from those EUGSUs hoping to take advantage of the "actual to projected actual" test. The final rule limited the "actual-to-projected-actual" test to **only** those utilities that satisfy post-project recordkeeping and reporting requirements. This change was intended to address valid concerns raised by the public during the notice and comment rulemaking process:

An environmental group and several State agencies noted that

¹⁹ Moreover, as EPA has frequently noted, the "not begun normal operations" phrase in the actual-to-potential methodology, 40 C.F.R. § 52.21(b)(21)(iv) (1980-2002), means that the facility has undergone a non-exempt modification. 63 Fed. Reg. 39,857, 39,858 (July 24, 1998) ("changes to a unit at a major stationary source that are non-routine or not subject to one of the other major source [PSD] exemptions are deemed to be of such significance that... 'normal operations' are deemed not to have begun following the change"); *In re Monroe Elec. Gen. Plant*, Petition No. 6-99-2, Order at 15 n. 15 (EPA Adm'r, June 11, 1999) (64 Fed. Reg. 44009 (Aug. 12, 1999)) ("For units that have not 'begun normal operations,' the regulations generally provide that actual emissions are equal to the unit's 'potential to emit.' EPA interprets this provision to mean that units which have undertaken a non-routine physical or operational change have not 'begun normal operations' within the meaning of the PSD regulations, since pre-change emissions may not be indicative of how the units will be operated following the non-routine change."); *Sierra Club v. Morgan*, 2007 U.S. Dist. LEXIS 82760 (W.D. Wis. 2007) ("in general when a major emitting source undergoes a physical change, as opposed to routine maintenance, the modified source does not begin "normal operations" until the change is complete requiring application of the "actual to potential" test").

the projected post-change emissions should become an enforceable permit condition in order to commit a source to limit its future emissions to a specific amount and to provide assurance that these projections are reasonable estimates of expected emissions. If a source will not accept such a permit condition, then the source should have to use potential post-change emissions.

57 Fed. Reg. at 32,324. EPA's final rulemaking agreed with these comments that extending the "actual-to-projected-actual" test to all EUGSUs would be problematic and therefore included important monitoring and reporting conditions on the test in the final rule.

After a thorough review of the comments, EPA concludes that the comparison of "actual emissions before" to a projection of "actual emissions after" a physical or operational change at an existing utility steam generating unit is workable and, ***with the added safeguard discussed below***, is the most suitable method for evaluating emissions changes at such sources.

...

Several commenters opposing today's regulatory changes charged that without appropriate assurances utilities could deliberately underestimate future operations (and thus emissions) for the purpose of avoiding review or that even where a forthright estimate is made, the forecast may prove inaccurate. The EPA is concerned that ***without appropriate safeguards*** increases in future actual emissions that in fact resulted from the physical or operational change could go unnoticed and unreviewed. ***For this reason, EPA has added the safeguard explained below.***

...

To guard against the possibility that significant increases in actual emissions attributable to the change may occur under this methodology, EPA is clarifying in the final regulations that ***any utility which utilizes the "representative actual annual emissions" methodology to determine that it is not subject to NSR must submit*** for 5 years after the change sufficient records to determine if the change results in an increase in representative actual annual emissions.

57 Fed. Reg. at 32,324-32,325 (emphasis added); *see also New York I*, 413 F.3d at 34 (describing the 1992 WEPCO Rule as requiring “utilities whose projections included no significant emissions increase” from a modification “to supply permitting authorities with a minimum of five years of data to verify the projections’ accuracy”) (citing 57 Fed. Reg. at 32,336); 63 Fed. Reg. at 39,859.

The WEPCO Rule’s mandatory reporting obligations for plants electing to use the actual-to-projected-actual test is essential to a workable regulatory program. *See New York*, 413 F.3d at 35 (rejecting EPA’s attempt to extend the actual-to-projected-actual test in 2003 to plants that did not meet minimum necessary monitoring and reporting obligations). EPA devised this “reasonable means of determining whether a significant increase in” emissions occurs, 57 Fed. Reg. at 32,325, by clearly putting the onus on EUSGUs opting to apply the actual-to-projected-actual test to: (1) keep records, (2) report emissions following the modification to the regulators, and (3) to prove to the regulatory agencies each year for at least five years that emissions did not, in fact, increase. 63 Fed. Reg. 39,857, 39,859 (July 24, 1998) (“To guard against the possibility that significant unreviewed increases in actual emissions would occur under this methodology, the regulations provide that sources... demonstrate that the change has not resulted in an increase above baseline levels.”). It is this post-project reporting and demonstration by the facility that provides the necessary safeguard to ensure that applicability of PSD to modifications is straightforward, rather than forcing an enforcement action to prove, years later, through needlessly expensive expert battles in district court, what the polluter should have projected prior to undertaking the project in the first place. *See, e.g., New York I*, 413

F.3d at 35 (agreeing that “the intricacies of the actual-to-projected-actual methodology” makes enforcement difficult without post-project recordkeeping and reporting by which to measure the reasonableness of a source’s projections); *see also WEPCO*, 893 F.2d at 917 (“EPA cannot reasonably rely on a utility’s own unenforceable estimates of its annual emissions...”).

EPA has long interpreted its own regulations as applying the “actual-to-potential” test to EUSGUs that fail to meet the reporting obligations under the 1992 WEPCO rulemaking. In a May 2000, guidance letter, EPA explained that the actual-to-projected-actual test in the 1992 WEPCO Rule can only be used by a utility that meets the monitoring and reporting requirements on which that test is conditioned.

For electric utility steam generating units, the post-change emission increase calculation is governed by regulations adopted in 1992 (57 Fed. Reg. 32,314, July 21, 1992), commonly referred to as the “WEPCO rule.”... A utility making a particular change, instead of accepting permit restrictions on the potential of the changed unit to emit a particular pollutant, may avoid PSD if its projection of “representative actual annual emissions” following the change is not significantly greater than its pre-change emissions, **but only if** the source “maintains and submits to the Administrator [or relevant state permitting authority] on an annual basis for a period of 5 years from the date the unit resumes regular operation, information demonstrating that the physical or operational change did not result in an emissions increase.” E.g., 40 C.F.R. § 52.21(b)(21)(v).

...

If [the utility] **fails to comply** with the reporting requirements of the WEPCO rule... **it will be required to obtain a PSD permit....**

Letter from Francis X. Lyons, EPA, to Henry Nickel, Counsel for Detroit Edison Co., Enclosure at 18-19, 22 n.14 (May 23, 2000)²⁰. Similarly, in 2002, EPA again noted that the 1992 WEPCO rule “require[es] that, for any modified emissions unit using the actual-to-[projected]-actual test, you must submit for 5 years after the change sufficient records to demonstrate that the change has not resulted in a significant emissions increase over the baseline levels.” 67 Fed. Reg. 80,186, 80,193 (Dec. 31, 2002). In filings with the Environmental Appeals Board, EPA again described the conditional nature of the “actual-to-projected-actual” test:

[T]he WEPCO rule alters how emissions increases are calculated from electric steam generating units... the rule enables post modification actual emissions to be determined by projecting the “representative actual annual emissions” of the unit... [However] the rule by its terms is provisional; a source may use the methodology *only if it submits* “on an annual basis, for a period of at least 5 years from the date the unit resumes regular operations, information demonstrating that the physical or operational change did not result in an emissions increase...” E.g., 40 C.F.R. § 51.166(b)(21)(v). Additionally, the rule specifies that the permitting authority is to make the ultimate projection of future emissions, *id.*, § 51.166(b)(32) (“In projecting future emissions the reviewing authority shall” consider various facts) (emphasis added), so ***failing to submit information enabling the permitting authority to project emissions likewise would prohibit a source from using these provisions.***

Initial Brief of the U.S. Environmental Protection Agency Enforcement 39-41, *In re Tennessee Valley Authority*, Case No. CAA-2000-04-008 (emphasis added), attached as Exhibit 23; *see also* Reply Brief of the U.S. Environmental Protection Agency Enforcement 56-57, *In re Tennessee Valley Authority*, Case No. CAA-2000-04-008 (explaining that EPA’s

²⁰ Available at <http://www.epa.gov/region7/air/nsr/nsrmemos/detedisn.pdf>

1992 WEPCO rule “made an actual-to-projected-actual test available to such changes, but only when two prerequisites were satisfied...”, and further that “the rules themselves are expressly provisional, applying only where sources submit sufficient pre- and post-change emissions information to enable the permitting authority to calculate whether emissions would increase from the change.”) (citing 40 C.F.R. §§ 52.21(b)(21)(v); (b)(33)), attached as Exhibit 24.²¹ Similarly, in a filing with the Middle District of North Carolina, EPA described its intention behind the WEPCO Rule: that where a utility opts-out of the 1992 future-actual method, the actual-to-potential test applies. Pls. Mem. Supp. Partial Sum. J. at 35 and n.14, *U.S. v. Duke Energy*, Case No. 1:00-cv-1262 (M.D.N.C., filed 1/31/03) (noting that the “actual-to-potential” test applies because Duke failed to satisfy the WEPCO rule’s reporting requirements), attached as Exhibit 25. And again in 2007, EPA stated that under the 1992 WEPCO Rule, any EUSGU that utilizes the “representative actual annual emissions methodology” must maintain and submit sufficient records showing that the change did not result in an emission increase. 72 Fed. Reg. 10,445, 10,447 (March 8, 2007).

Thus, an EUSGU that fails to satisfy the reporting requirements upon which the actual-to-projected-actual test is conditioned—as the Valley plant has here—is prohibited from using the representative-actual test and must default to the actual-to-potential test. Moreover, prior to the 1992 WEPCO Rule, any facility that makes a change to the original design of the facility has not “begun normal operations,” and therefore must apply the actual-to-potential test. Here, WEPCO reported emissions prior to each

²¹ The Environmental Appeals Board did not reach this issue because the case was a review of a compliance order, in which the EPA Region initially chose to apply the more-favorable to the defendant “projected actual” test to TVA based on its enforcement discretion. *In re Tennessee Valley Authority*, 9 E.A.D. 357, 434-35 (EAB 2000). The Board expressed no opinion on the issue. *Id.*

superheater/economizer replacement as follows:

Unit 1 Emissions (in tons/year)²²

	1989	1990	1991	1992	1993
SO₂	2,708	3,829	3,662	3,963	3,489
NOx	995	1,320	1,188	1,286	1,290
PM	50.60	55.80	47.53	50.70	49.41

Unit 2 Emissions (in tons/year)²³

	1986	1987	1988	1989	1990
SO₂	3,221	2,767	3,353	3,004	3,587
NOx	1,276	1,060	1,163	1,104	1,236
PM	30.63	27.53	31.89	28.07	26.14

Unit 3 Emissions (in tons/year)²⁴

	1982	1983	1984	1985	1986
SO₂	na	9,312	5,985	3,870	2,925
NOx	na	1,921	1,535	1,385	1,151
PM	na	169.09	135.04	116.35	97.83

²² Source: Fox Report (Ex. 10) Exhibit 1 (Emissions reported by WEPCO to Wisconsin DNR).

²³ Source: Fox Report (Ex. 10) Exhibit 1 (Emissions reported by WEPCO to Wisconsin DNR).

²⁴ Source: Fox Report (Ex. 10) Exhibit 1 (Emissions reported by WEPCO to Wisconsin DNR).

Unit 4 Emissions (in tons/year)²⁵

	1984	1985	1986	1987	1988
SO₂	6,484	3,659	3,026	2,137	3,206
NOx	1,662	1,310	1,191	842	1,126
PM	69.67	52.39	48.20	37.64	51.47

Each boiler's potential to emit was as follows:

	PTE from Analysis and Preliminary Determination for Permit 241007800-P01 (in tons/year)
SO₂	12,154
NOx	6,079
PM²⁶	1447

The difference between any 2-year period annual emission rate prior to the project and the potential to emit after the project is greater than 40 tons of SO₂, 40 tons of NOx and 25 tons of PM.

²⁵ Source: Fox Report (Ex. 10) Exhibit 1 (Emissions reported by WEPCO to Wisconsin DNR).

²⁶ The Analysis and Preliminary Determination document authored by Wisconsin DNR calculates the "maximum theoretical" emissions and what purports to be the "potential to emit." However, neither appropriately accounts for the emission limitation, without also assuming what appears (in the PTE calculation) to be an unenforceable pollutant control efficiency of 99.92%. Therefore, the PTE here represents the emission rate assumed in DNR's emission modeling as the maximum annual emission rate.

ii. Even If The Actual-to-Representative-Actual Test Applies, The Projects Resulted in Significant Increases.

Even if the actual-to-representative-actual test for measuring emission increases applies, the superheater/economizer replacement projects resulted in significant emission increases due to regained hours of operation directly attributable to the project(s). *See* Fox Report at 49-54. Moreover, while not a recognized test where a facility fails to do post-project “backstop” reporting (as the Valley plant failed to do here), it is interesting to note that if the Valley plant had done “backstop” reporting under the 1992 WEPCO Rule, it would have reported emission increases. *See* Fox Report at 55-57.

2. The Valley Plant Also Underwent Changes in the Method of Operation By Switching to Petroleum Coke and Then By Increasing the Amount of Coke.

Switching the fuels for the Valley plant from coal to a mixture of coal and petroleum coke was a major modification for sulfur dioxide (and likely for sulfuric acid mist and particulate matter) triggering requirements of the PSD program unless exempt pursuant to 40 C.F.R. § 52.21(b)(2)(iii)(e)(1998). *See also* Wis. Admin. Code § NR 405.02(21)(b)5.(1998). The PSD regulations define a modification as any physical or operational change that is not specifically exempt. The only relevant exemption here states:

A physical change or change in the method of operation shall not include: ...

Use of an alternative fuel or raw material by a stationary source which:

The source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any

federally enforceable permit condition which was established after January 6, 1975 pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR subpart I or 40 CFR 51.166...

40 C.F.R. § 52.21(b)(2)(iii)(e)(1980); *see also* Wis. Admin. Code § NR 405.02(21)(b)5 (1998).

Burning pet coke at as a supplemental fuel at the Valley plant does not qualify for this fuel-change exemption to the definition of “modification” for the PSD and NSPS programs because the use of petroleum coke as a *supplemental* fuel, rather than a *primary* fuel, does not qualify for the exemption which only applies to changes in the main fuel. As U.S. EPA has explained in numerous Title V objections, 40 C.F.R. § 52.21(b)(2)(iii)(e)(1) does not apply to use of pet coke as a *supplemental* fuel. *See* Objection by U.S. EPA to Title V Permit No. 0170004-004-AV, Florida Power Corporation Crystal River Plant (November 1, 1999) (hereafter “Crystal River Objection”)²⁷.

As discussed in *Alabama Power Co. v. Costle*, the PSD exemption at 40 C.F.R. § 52.21(b)(2)(iii)(e)... [was] intended to grandfather “voluntary fuel switches by emission sources which were designed to accommodate the alternative fuels prior to January 6, 1975.” The provision was not intended to provide a loop-hole by which facilities may add various substances, such as waste products or waste fuels, to their primary fuels without being subject to PSD review. The Federal Register notices and background information documents that speak to this particular exemption only reference primary fuels, such as coal, oil and gas. At the time the alternative fuels exemption was promulgated, EPA contemplated “switches” between primary fuels. Therefore, it is a reasonable interpretation of the regulations to limit this

²⁷ Available at <http://www.epa.gov/region4/air/permits/TitleVObjectionLetters/FL.ObjectionLetters/FPC-CrystalRiver.pdf>

exemption to primary fuels and not to apply the exemption to fuel additives that the facility was neither designed nor built to use as a primary fuel. FPC is currently burning coal as their primary fuel. *It is EPA's determination that burning a 95% coal, 5% pet coke blend does not constitute a "switch" to an "alternative" fuel as intended by the exemption. Rather, the blending in of 5% pet coke is a change in the current method of operation that is subject to PSD review.*

The above interpretations are consistent with... EPA's longstanding interpretations of the "capable of accommodating" exemption.

Id. at 8 of 12; *see also* U.S. EPA Objection to D.B. Wilson Station, Kentucky at 2-3 (August 20, 1999) (objecting based on a pet coke switch and stating "we note that a fuel like petcoke that is used as a supplemental fuel blended with a primary fuel does not qualify as an 'alternative' fuel in the sense originally envisioned when the alternative fuel exclusion was added to the federal PSD rules.")²⁸; U.S. EPA Objection to Title V Permit for Reid/Henderson Station, Kentucky at 2 (August 30, 1999) (same).²⁹

The Valley plant never switched to petroleum coke as a primary fuel. Instead, it only burned petroleum coke as a supplemental fuel. Therefore, because the fuel blending does not constitute the use of an "alternative fuel" within the meaning of 40 C.F.R. § 52.21(b)(2)(iii)(e)(1998), the change is a "modification" triggering PSD requirements.

²⁸ Available at http://www.epa.gov/region4/air/permits/TitleVObjectionLetters/KY_ObjectionLetters/WKEC-DBWilson.pdf

²⁹ Available at http://www.epa.gov/region4/air/permits/TitleVObjectionLetters/KY_ObjectionLetters/KYobjections.htm

IV. THE SWITCH TO PETROLEUM COKE AND SUBSEQUENT INCREASES IN COKE USE TRIGGERED NEW SOURCE PERFORMANCE STANDARDS THAT ARE NOT INCLUDED IN THE PERMIT.

Pursuant to Section 111 of the Clean Air Act, 42 U.S.C. § 7411, has promulgated New Source Performance Standards (“NSPS”) for categories of new stationary sources that cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. Fossil fuel fired steam generators, like the Valley plant, have been regulated by NSPS standards since August 17, 1971, in 40 C.F.R. Part 60, Subparts D and Da. Clean Air Act section 111(e), 42 U.S.C. § 7411(e), prohibits operation in violation of any NSPS requirement. NSPS standards must be included as applicable requirements in Title V permits. 40 C.F.R. § 70.2

NSPS standards apply to “any stationary source, the construction or modification of which is commenced after the publication of” an applicable standard. 42 U.S.C. § 7411(a)(2). A “modification” is defined as “any physical change in or change in the method of operation of, an existing facility which increases the amount of any air pollutant ... emitted into the atmosphere by that facility...” 40 C.F.R. § 60.2. More specifically, 40 C.F.R. § 60.14(a) defines a “modification,” which triggers the application of NSPS to an affected facility, as “any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies...”³⁰ An increase in “emission rate,” in turn, is measured by an increase in hourly emissions. 40 C.F.R. § 60.14(b). Unless the U.S. EPA Administrator has approved a

³⁰ “Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.” 40 C.F.R. 60.14(a).

different method for the specific emission source and project at issue, emission rate increases are determined based on U.S. EPA's "Compilation of Air Pollutant Emission Factors," EPA Publication No. AP-42. 40 C.F.R. § 60.14(b)(1).³¹

Switching from coal to a mixture of coal and petroleum coke is a modification. The NSPS program provides exemptions for certain fuel switches pursuant to 40 C.F.R. § 60.14(e)(4), which provides:

The following shall not, by themselves, be considered modifications under this part:

...

Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by § 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change....

See also Wis. Admin. Code § NR 440.14(5)(d). This provision only applies to a change in primary fuels, however, as noted above. It does not apply to adding a supplemental fuel, as petroleum coke was used at the Valley plant. *See* Crystal River Objection, *supra*; Objection to D.B. Wilson Station, *supra*; Objection to Reid/Henderson Station, *supra*. Moreover, there is no indication that the Valley boilers were designed to accommodate petroleum coke. In fact, the record indicates the opposite. Application for Permit 97-JCH-231 at 43 (describing boilers as "burning coal as the primary fuel" with "[n]atural gas or propane is used as an

³¹ Here, the increase is obvious. Petroleum coke has a much higher sulfur content than the coal that was being used at the Valley plant prior the fuel switch. *See e.g.*, Petroleum Coke Data Sheets, attached as Exhibit 30 (showing sulfur content above 5% by weight). The applicable AP-42 emission factor is directly correlated to the fuel sulfur content. *See* AP-42 § 1.1, Table 1.1-3.

ignition fuel during boiler start-up and shutdown and for flame stabilization,” and noting that the 1997 application “requests the capability to fire a blend of petroleum coke), attached as Exhibit 26; Preliminary Determination for 97-JCH-231 at 3, attached as Exhibit 27; Preliminary Determination for Mandatory Operation Permit 1990 at 1-2, 5 (May 16, 1988), attached as Exhibit 28; Application for Mandatory Operating Permit at 4-16 (listing coal and natural gas as only fuels), attached as Exhibit 29. Notably, the regulations that exempt fuel changes from the definition of modification require that the emission unit be specifically designed for the fuel, not merely that by happenstance the new fuel can be burned in the boiler without redesigning it. In other words, a new fuel had to have been specifically expected and anticipated during the design of the unit. *See* Crystal River Objection, *supra*, at § I.1.B (noting that the purpose of the “alternative fuels” provision was to address instances where a fuel was considered in the design and construction documents for a facility).

V. THE PERMIT FAILS TO INCLUDE APPLICABLE REQUIREMENTS FROM THE WISCONSIN SIP THAT WERE TRIGGERED BY PRIOR MODIFICATIONS

In addition to the PSD program applicable requirements that were triggered by modifications at the plant, lower State Implementation Plan (SIP) limits were also triggered by modifications.

The Wisconsin SIP provides different particulate matter emission limits depending on when a facility was last modified. The Permit establishes a limit of 0.15 lb/MMBtu for particulates from the boilers. Permit § I.A.1.a.(1). The Permit indicates that this limit is based on Wis. Admin. Code § NR 415.06(1)(c)(2) and NR 415.06(3)(b). However, those provisions apply to boilers that were last modified on or before April 1, 1972. For plants

that have been modified since April 1, 1972, a lower emission rate of 0.10 lb/MMBtu applies. *See* Wis. Admin. Code § NR 415.06(2)(c), 415.06(3)(d). The modifications set forth above triggered these lower SIP limits and it was an error for the Wisconsin DNR not to include them in the Permit.

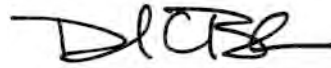
Moreover, there is no dispute that the Valley boilers have been modified since 1972. The Wisconsin DNR issued construction permits 97-JCH-231 and 98-JCH-175 for modifications to the boilers in 1997 and 1999, respectively. *See e.g.*, Ex. 6 at 1 (“The 98-JCH-175 construction permit was to allow the utility to increase the burning rate of petroleum coke from 20% to 27.5%. ***This was a modification*** because of the increase in hazardous air emissions.”) (emphasis added)). Therefore, the permit erroneously omits the lower 0.10 lb/MMBtu particulate matter limits.

Conclusion

For the foregoing reasons, the permit fails to meet federal requirements in numerous ways. These deficiencies require that the Administrator object to issuance of the permit pursuant to 40 C.F.R. § 70.8(c)(1). Each of the issues raised by Clean Wisconsin and Sierra Club in this petition result in a deficient permit. Most of the deficiencies result in unlawful emissions of air pollutants that negatively affect the health and welfare of Clean Wisconsin and Sierra Club members. Others result in illegal monitoring and reporting that make it difficult for the public to monitor and enforce air pollution limits applicable to the plant.

Dated this 25th day of March, 2011.

Attorneys for Sierra Club
MCGILLIVAY WESTERBERG & BENDER LLC

A handwritten signature in black ink, appearing to read "DCB", with a stylized flourish extending to the right.

David C. Bender

CERTIFICATE OF SERVICE

STATE OF WISCONSIN)
) ss
COUNTY OF DANE)

I make this statement under oath and based on personal knowledge. On this day I caused to be served upon the following persons a copy of Clean Wisconsin and Sierra Club's Petition to the United States Environmental Protection Agency regarding the Valley Power Plant, Permit Number 241007800-P20

To Administrator Jackson via electronic mail to: jackson.lisa@epa.gov and via Federal Express, next day delivery, to:

Lisa Jackson
US EPA Administrator
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Via personal service to the Office of the Secretary:

Wisconsin Dept. of Natural Resources Secretary
101 S Webster St
PO Box 7921
Madison, WI 53707-7921

And via common carrier for delivery within three business days to:

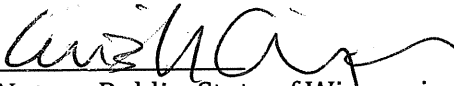
Valley Power Plant
1035 W. Canal Street
Milwaukee, WI 53233

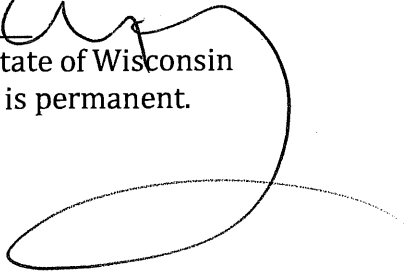
Wisconsin Electric Power Company
231 W. Michigan St.
Milwaukee, WI 53203

Dated: March 28, 2011.

A handwritten signature in black ink, consisting of several loops and a horizontal line at the end.

Signed and sworn to before me
This 28th day of March, 2011.


Notary Public, State of Wisconsin
My commission is permanent.

A large, handwritten signature in black ink, featuring a prominent loop and a horizontal line.