BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF THE FINAL OPERATING AIR QUALITY PERMIT FOR ENTERGY ARKANSAS, INC. - WHITE BLUFF PLANT ISSUED BY THE ARKANSAS DEPARTMENT OF ENVIRONMENTAL QUALITY	)	Permit No. 0263-AOP-R7

SIERRA CLUB'S SUPPLEMENT TO ITS ORIGINAL PETITION AND/OR ORIGINAL PETITION TO OBJECT TO THE TITLE V OPERATING PERMIT FOR THE WHITE BLUFF PLANT ISSUED BY THE ARKANSAS DEPARTMENT OF ENVIRONMENTAL QUALITY (PERMIT NO. 0263-AOP-R7)

Pursuant to § 505(b)(2) of the Clean Air Act, 42 U.S.C. § 7661d(b)(2), and 40 C.F.R. § 70.8(d), the Sierra Club ("Petitioner") hereby petitions the Administrator ("Administrator") of the United States Environmental Protection Agency ("EPA") to object to the final Title V renewal permit for Energy-Arkansas, Inc.'s ("EAI" or "Entergy") White Bluff plant, that was issued in draft form and submitted to EPA by the Arkansas Department of Environmental Quality ("ADEQ") in October 2011, Draft White Bluff Title V Permit (No. 0263-AOP-R7) (Ex. 63), was submitted to EPA again on May 18, 2012, May 2012 White Bluff Title V Renewal Permit (No. 0263-AOP-R7), and was finally issued in final form with substantial changes by ADEQ on August 9, 2012. Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) (Ex. 72). Notice of the original draft renewal permit was published on October 25, 2011 in the Pine Bluff Commercial by ADEQ.

The White Bluff plant is located in Redfield, Arkansas and is comprised of two identical

coal-fired units (Units 1 and 2), each with a nominal generating capacity of 845 megawatts (MW). Draft White Bluff Title V Renewal Permit at 5 (Ex. 63). Unit 1 and Unit 2 began commercial operations in 1980 and 1981, respectively. January 2009 Application for Permit to Construct Entergy White Bluff Units 1 & 2 Air Pollution Control Project at 2-4 (Ex. 10);[1] January 2009 Application for Permit to Construct Entergy White Bluff Units 1 & 2 Air Pollution Control Project at 15 (Ex. 64).[2] As explained in detail below, because numerous aspects of the White Bluff Title V renewal permit are unlawful, EPA is obligated to object to the permit.

THE SIERRA CLUB

The Sierra Club is a national non-profit corporation organized and existing under the non-profit corporation laws of the state of California. The Sierra Club, a national conservation organization with over 600,000 members, is dedicated to protecting natural resources, including clean air and water. Sierra Club's national office is located at 85 Second Street, San Francisco, CA 94105. The office of the Arkansas Chapter of Sierra Club is located at 1308 West 2nd Street Little Rock, Arkansas.

Sierra Club exists for the purposes of preserving and protecting the environment and has been actively engaged in protecting air quality and other environmental values throughout the nation, including Arkansas, for years. Since 1981, Sierra Club's stated purposes in its Articles of Incorporation (www.sierraclub.org/policy/articles_current.asp) have been:

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[1] The date on the cover letter to this document of February 4, 2008 appears to be a typographical error. The cover letter enclosing this exhibit (and the same cover letter in the pdf version of this exhibit at Ex. 64) was almost certainly drafted on February 4, 2009.

[2] This is the same document as Ex. 10, which was included in Sierra Club's comment letter of November 23, 2011 to ADEQ, only saved in a pdf format.

> to explore, enjoy, and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives.

The members of Sierra Club in Arkansas have a strong interest in protecting and enhancing the quality of ambient air in that state and the entire region. Sierra Club members reside in, work in, visit and/or use the resources in the same region as the White Bluff Plant and those members' aesthetic, recreational, environmental, economic and health-related interests will be injured and otherwise adversely impacted by the operations and corresponding emissions of the White Bluff plant if it is permitted as proposed.

PROCEDURAL BACKGROUND

ADEQ previously issued a combined Prevention of Significant Deterioration ("PSD"), draft Title V and Best Available Retrofit Technology ("BART") permit for the White Bluff for public review and comment in October 2009.[3] That earlier permit was created to encompass and allow for the installation of a set of controls intended to comply with anticipated regional haze and BART requirements. Sierra Club provided ADEQ with detailed comments on that permit on November 24, 2009 and filed a petition with EPA to object to that permit on January 27, 2010. However, the prior permit was never issued, due in part to the fact that Arkansas adopted a variance extending indefinitely the BART compliance deadline for BART-subject sources such as White Bluff.

A second draft White Title V renewal permit (Draft Permit No. 0263-AOP-R7), which was intended to replace the prior White Bluff Title V Permit (No. 0263-AOP-R6) issued on

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[3] That prior combined PSD, Title V and BART renewal permit was assigned the same permit number as the draft and final Title V permits, Permit No. 0263-AOP-R7.

January 12, 2009, was noticed to the public by ADEQ on October 25, 2011. Sierra Club timely submitted it first set of written comments to ADEQ regarding that draft White Bluff Title V permit on November 23, 2011. *See* 11/23/11 Sierra Club's Comments on the Draft Title V Renewal Permit for the Entergy Arkansas White Bluff Plant (Draft Permit No. 0263-AOP-R7) (Ex. 67).[4] ADEQ held a public hearing on the draft White Bluff Title V renewal permit on January 10, 2012, at which both oral and written comments were accepted. Sierra Club submitted an additional set of timely written comments at this public hearing on the draft permit. 1/10/12 Sierra Club's Additional Comments on the Draft Title V Renewal Permit for the Entergy Arkansas White Bluff Plant (Draft Permit No. 0263-AOP-R7) (Ex. 68).[5]

On October 20, 2011, five (5) days prior to the issuance of the public notice in Arkansas, ADEQ submitted that draft White Bluff permit to EPA for what ADEQ contended was a 45-day review period. EPA Region 6's Operating Permit Timeline for Arkansas as published on EPA Region 6's website at that time at (http://yosemite.epa. gov /r6/Apermit.nsf/AirAR?OpenView& Start=1& Count=4000&Expand= 1#1) (Ex. 69). According to EPA Region 6's website, EPA's 45-day review period on this version of the draft White Bluff permit ended on December 4, 2011 and the public petition deadline ended on February 2, 2012. *Id.*

Despite its reservations and objections relating the timing and the EPA review process, *see* discussion *infra*, Sierra Club complied with EPA's deadline and served and filed a petition on February 1, 2012. EPA failed to respond to that petition in any manner.

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[4] The exhibits to Sierra Club's November 23, 2011 letter to ADEQ, Exs. 1-20, are attached to this Title V petition as Exs. 1 - 20.

[5] The exhibits to Sierra Club's January 10, 2012 letter to ADEQ, Exs. 21-62, are attached to this Title V petition as Exs. 21-62.

Recently, Sierra Club learned that ADEQ had submitted another revised Title V permit (Draft Permit No. 0263-AOP-R7) to EPA, along with ADEQ's Response to Comments ("May 2012 ADEQ Response to Comments" (Ex. 74)) on the prior permit notice in October 2011. *See* E-mail Chain Between EPA and ADEQ from May 18, 2012 to June 13, 2012 (5/18/12 e-mail from ADEQ's T. Rheaume to EPA's J. Robinson enclosing new permit and response to comments) (Ex. 73). ADEQ did not expressly recognize that it was providing a "proposed" or "draft" permit to EPA or that this submission formally triggered a forty-five (45) day EPA review period. ADEQ merely stated in the e-mail message that the ADEQ's Response to Comments and a "copy of the pre-decisional (unsigned) final permit which reflects revisions to the draft permit in response to comments received" was attached. *Id.*; *see also* May 2012 ADEQ Response to Comments at 13 ("[T]his Response to Comments document along with a copy of the ***pre-decisional (unsigned) final permit*** which reflects revisions to the draft permit in response to comments received was provided to EPA as requested on May 18, 2012.") (emphasis added) (Ex. 74). However, EPA treated this submission as though it started a new forty-five (45) review for EPA and opened up a new petition period for the public. At some point after the submission from ADEQ was sent to EPA, EPA Region 6's website posted that EPA's 45-day review period on the unsigned final White Bluff Title V permit began on May 18, 2012, closed on July 1, 2012, and that the deadline for filing a petition and the public petition deadline ends on August 30, 2012. EPA Region 6's Current Operating Permit Timeline for Arkansas (http//yosemite.epa.gov/r6/Apermit.nsf/AirAR?OpenView&Start =1&Count=4000&Expand =1#1) (Ex. 75). Subsequent to this posting by EPA, on August 9, 2012, ADEQ issued a final version of the White Bluff Title V permit, which included substantial changes from the version

that EPA had reviewed. Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) (Ex. 72). And also on August 9, 2012, ADEQ issued a new response to comments, August 2012 ADEQ Final Response to Comments (Ex. 76), which included changes from what EPA had been provided to review, and a new statement of basis. August 2012 ADEQ Statement of Basis for Permit 0263-AOP-R7 (Ex. 77).

In an abundance of caution, Sierra Club has timely filed this petition to ensure that the new EPA deadline is not violated and that a petition is properly filed seeking an objection to any and all versions of the White Bluff Title V permit. Sierra Club requests that this be treated as a supplement to its original February 2, 2012 petition or, alternatively, as an original petition. Sierra Club bases this petition on its comments and associated exhibits filed on November 23, 2011 and January 10, 2012. Because the new revised Final White Bluff Title V renewal permit and ADEQ's final response to comments were only issued twenty-one (21) days before Sierra Club's petition deadline expired, Sierra Club has not had sufficient time to review and fully respond to those changes. For that reason, Sierra Club reserves the right to supplement or revise this petition as necessary and appropriate.[6]

REGULATORY FRAMEWORK

Title V of the Clean Air Act, 42 U.S.C. §§ 7661-7661f, prohibits any person from operating a major stationary air pollution source such as White Bluff without an operating

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[6] To the extent that EPA's determines that any of Sierra Club's arguments contained herein raise any new objections related to these recent permit changes, which appears very unlikely, it was impracticable for Sierra Club to raise such objections within such period as the grounds for such objections stemmed from the recent permit changes that arose after the public comment period closed on the subject permit.

permit. A Title V operating permit must include all applicable requirements, including all applicable emission limitations and standards, and must include provisions assuring compliance with those requirements. 42 U.S.C. § 7661c(a); 40 C.F.R. § 70.1(b); APCEC Reg. 26.402(4)(a) and (8)(a), (b)(iii) and (c) (iii). The federal operating permit regulations provide that "[w]hile title V does not impose substantive new requirements. . .[a]ll sources subject to these regulations shall have a permit to operate that assures compliance by the source with all applicable requirements." 40 C.F.R. § 70.1(b).

The regulations in 40 C.F.R. Part 70, which govern state operating permit programs required under Title V of the Clean Air Act, require Title V permits to assure compliance with all "applicable requirements." The term "applicable requirements" is defined in the federal rules as including any provision of the state implementation plan ("SIP"), any term or condition of a preconstruction permit issued pursuant to regulations approved under Title I of the Clean Air Act including under Parts C and D of the Act, any standard or requirement under Sections 111, 112, 114(a)(3), or 504 of the Act, as well as the Act's Acid Rain program requirements. 40 C.F.R. § 70.2; APCEC Reg. 26, Chapter 2 (definition of "applicable requirement").

Arkansas has a combined pre-construction/Title V permit program for those modifications that are subject to significant permit modification procedures. APCEC Reg. 26.301(C) provides:

> No part 70 source shall begin construction of a new emissions unit or begin modifications to an existing emissions unit prior to obtaining a modified part 70 permit. This applies only to significant modifications and does not apply to modifications that qualify as minor modifications or changes allowed under the operational flexibility provisions of a part 70 permit.

APCEC Reg. 26.1010 provides that, among other things, "significant modifications" include any

modifications under Title I of the Clean Air Act. "Title I modification" is defined in APCEC Reg. 26, Chapter 2 to mean "any modification as defined under any regulation promulgated pursuant to Title I of the Federal Clean Air Act." This would include prevention of significant deterioration ("PSD") major modifications. Further, APCEC Reg. 26.1010 provides that "significant modifications" include "applications that involve new applicable requirements" and that "seek to establish a permit term or condition...that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject."

Arkansas has adopted regulations implementing the federal PSD regulations at APCEC Reg. 19, Chapter 9. These regulations have been most recently approved by EPA as part of the SIP on April 12, 2007. 72 Fed. Reg. 18394 (April 12, 2007).

A Title V permit is issued for up to five years, 40 C.F.R. § 70.6(a)(2), and the source owner must submit an application for renewal of a permit "at least six months prior to the date of permit expiration, or such other longer time as may be approved by the Administrator that ensures that the term of the permit will not expire before the permit is renewed." 40 C.F.R. § 70.5(a)(1)(iii), APCEC Reg. 26.406. Permits being renewed are subject to the same procedural requirements, including those for public participatio2n and affected state and EPA review that apply to initial permit issuance. 40 C.F.R. § 70.7(c)(1)(i); APCEC Reg. 26.406. Under the federal and Arkansas Title V regulations, the public has the right to petition EPA to object to a Title V permit if EPA fails to object to the proposed permit during its 45 day review period. 40 C.F.R. § 70.8(d); APCEC Reg. 25.606.

This petition is timely filed because it is being filed within sixty days from the end of EPA's most recently established 45-day review period as required by Clean Air Act § 505(b)(2)

and 40 C.F.R. § 70.8(d).[7] *See also* APCEC Reg. 25.606. Accordingly, the Administrator must grant or deny this petition within sixty (60) days. 42 U.S.C. § 7661d(b)(2). If the Administrator determines that the White Bluff Title V renewal permit does not comply with any applicable requirement or the requirements of 40 C.F.R. Part 70, EPA must object to the permit and EPA must terminate, modify or revoke the permit. 40 C.F.R. §§ 70.8(c)(1) and 70.8(d).

The 60-day deadline established in 42 U.S.C. § 7661d(b)(2) for EPA to respond to petitions is clearly intended to ensure that, if a source is failing to comply with applicable requirements of the Clean Air Act, EPA will remedy that noncompliance as soon as possible. In this specific situation, timely action by EPA is particularly important because air modeling analyses recently conducted by an independent modeling consultant working for Sierra Club have revealed that the White Bluff plant's allowable and actual SO2 emissions are causing violations of the 1-hour average National Ambient Air Quality Standard ("NAAQS") for SO2. *See* AERMOD Modeling of SO2 Impacts of the Entergy White Bluff Coal Plant, prepared for Sierra Club by Khanh T. Tran, AMI Environmental, September 28, 2011, at 6 (Table 2) (Ex. 21).

GROUNDS FOR OBJECTION

Issue #1: The Administrator Must Object to the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) Because it Was Issued Unlawfully and in Violation of the Rules Set Forth at APCEC Reg. 26.603(A), Clean Air Act Section 505, and 40 C.F.R. § 70.9(c)(3)(i) and (ii) Which Require ADEQ to Submit a "Proposed" Permit for EPA to Review

A substantial legal disagreement between EPA and ADEQ exists regarding the legal effect of the newly submitted permit and the Title V permitting process generally. And in this

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[7] As stated *supra*, EPA's new deadline for petitions on the unsigned final Title V permit for White Bluff (and presumably for the final permit as well) ends on August 30, 2012. EPA Region 6's Current Operating Permit Timeline for Arkansas (http//yosemite.epa.gov /r6/Apermit.nsf/AirAR?OpenView&Start =1&Count=4000&Expand =1#1) (Ex. 75).

instance, Sierra Club was caught in middle of this dispute and consequently forced to file two petitions to preserve its rights under the Act.[8]

The Arkansas Title V regulations at Arkansas Pollution Control and Ecology Commission Regulation (hereinafter "APCEC Reg.") 26.603(A) require, *inter alia*, the submittal to EPA of a "proposed permit," that is, "the version of a permit that [ADEQ] proposes to issue and forwards to the Administrator for review," *see* APCEC Reg. 26, Chapter 2 Definitions, for EPA's formal 45-day review period. *See* APCEC Reg.26.603(A). Accordingly, it is unlawful for ADEQ to issue a any Title V permit where EPA has only been provided a opportunity to review and object to a "draft permit," which "means the version of a permit for which the Department offers public participation and affected State review." *See* APCEC Reg. 26, Chapter 2 Definitions; *see also* APCEC Reg. 26.605(A) ("The Administrator will object to the issuance of ***any proposed permit*** determined by the Administrator not to be in compliance with applicable requirements or requirements under this regulation. No permit for which an application is required to be transmitted to the Administrator may be issued if the Administrator objects to its issuance in writing within 45 days of receipt of the ***proposed permit*** and all necessary supporting information.")(emphasis added). And APCEC Reg. 26.605(C) provides that the "[f]ailure of . . . [ADEQ] to follow proper permit issuance procedural requirements or to submit required information necessary to review the proposed permit also shall constitute grounds for an objection" by EPA.

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[8] Sierra Club appreciates the intentions of EPA in affording the public, including Sierra Club, full and meaningful due process and another clear entry point for filing a petition on the White Bluff Title V permit. Nevertheless, EPA's well-intended decision to provide for a new deadline for filing a petition meant that Sierra Club's burdens relating to its petition were twice what they should have been under the applicable rules.

Similarly, the federal Title V regulations at 40 C.F.R. 70.2, which the Arkansas rules should be consistent with, define the term "proposed permit" as the "version of a permit that the permitting authority proposes to issue and forwards to the Administrator for review in compliance with §70.8." Clean Air Act Section 505, 42 U.S.C. § 7661d, and 40 C.F.R. § 70.8(a)(1) and (c)(1) and (3) all require that each proposed permit be submitted to EPA for a forty-five (45) day review. *See In the Matter of Wheelabrator Baltimore, L.P., Baltimore, Maryland*, Permit No. 24-510-01886, Order at 2 (Adm'r April 14, 2010). Specifically, 42 U.S.C. § 7661d(a) states that "[e]ach permitting authority . . . (B) shall provide to the Administrator a copy of each permit ***proposed to be issued and issued as a final permit***." (emphasis added). 42 U.S.C. § 7661d(b) provides that in pertinent part:

> (1) If any permit contains provisions that are determined by the Administrator as not in compliance with the applicable requirements of this chapter, including the requirements of an applicable implementation plan, the Administrator shall, in accordance with this subsection, object to its issuance. The permitting authority shall respond in writing if the Administrator
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> (A) within 45 days after receiving a copy of the ***proposed permit under subsection (a)(1) of this section***, . . . objects in writing to its issuance as not in compliance with such requirements. . . . .
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> (2) If the Administrator does not object in writing to the issuance of a permit pursuant to paragraph (1), any person may petition the Administrator within 60 days after the expiration of the 45-day review period specified in paragraph (1) to take such action.

(emphasis added). And 40 C.F.R. § 70.8(a)(1) and (c)(1) and (3) provide in pertinent part:

> (a) Transmission of information to the Administrator. (1) The permit program shall require that the permitting authority provide to the Administrator a copy of each permit application (including any application for permit modification), ***each proposed permit***, and each final part 70 permit. The applicant may be required by the permitting authority to provide a copy of the permit application (including the compliance plan) directly to the Administrator. [emphasis added]. . .

(c) EPA objection. (1) The Administrator will object to the issuance of any ***proposed permit*** determined by the Administrator not to be in compliance with applicable requirements or requirements under this part. . . .

(3) Failure of the permitting authority to do any of the following also shall constitute grounds for an objection:

(i) Comply with paragraphs (a) [requiring the Permitting Authority to transmit the proposed permit, the permit application, and other information needed to effectively review the proposed permit] or (b) [requiring the Permitting Authority to give notice of the proposed permit to any affected state] of this section;

(ii) Submit any information necessary to review adequately the proposed permit; or

(iii) Process the permit under the procedures approved to meet § 70.7(h) of this part [governing public participation] except for minor permit modifications.

(emphasis added).

The plain meaning of the Arkansas Title V rules, even when read in isolation, establishes that EPA's 45-day review (and, consequently, the subsequent time frame for filing any petition with EPA) cannot start until a "proposed permit" is submitted to EPA, meaning the permit which ADEQ proposes to issue. When read in conjunction with the federal Title V rules, the principle that EPA's 45-day review cannot be initiated on a draft permit is even more clear.

Although EPA appears to agree with this reading of the Arkansas and federal Title V regulations, EPA Region VI has, either pursuant to an agreement with ADEQ or as a matter of practice or custom, endeavored to undertake its 45-day review period over draft permits so that EPA's review can be conducted concurrently with the public review, at least where no substantial comments are received.[9] This is and was unlawful as it is inconsistent with the state and federal

[9] Sierra Club did not understand that this agreement, custom or practice, which has never been disclosed to Sierra Club, would allow for an EPA review period to start before public review was

regulations as well as Section 505 of the Clean Air Act.

The following series of e-mails demonstrate that EPA and ADEQ are now clearly at odds over the critical legal issue of when EPA's 45-day review should start in Arkansas and highlights the problems that are being created by EPA's attempt to accommodate ADEQ by engaging in unlawful, preliminary concurrent reviews of draft permits.

On November 18, 2012, EPA Region 6's Jeff Robinson e-mailed ADEQ, stating:

> I wanted to make sure that we are on the same page with respect to Entergy White Bluff's Title V permit. As I understand, EPA's 45-day review period on the draft permit expires on December 4, 2011. It is our understanding that the public comment period on the draft permit expires on November 24, 2011. However, ADEQ has scheduled a public hearing on or about January 4, 2012, and in your letter to Sierra Club you've indicated that you will accept oral and/or written public comments on the draft permit during the hearing, and that a decision to extend the comment period by as much as 20 days may be made.
> I want to verify that if you receive comments from the public during either the public comment period or during the public hearing that you will then provide EPA a proposed permit for review and ADEQ's response to comments, and EPA will start a new 45-day review period for the proposed Title V permit and then we will begin the 60-day window for commenters to petition EPA on the permit. Please confirm whether we have a mutual understanding of how this permit will be processed if public comments are received by ADEQ.

E-mail Chain Between EPA and ADEQ from November 18, 2011 to January 19, 2012 (Ex. 78).

In response, ADEQ's Mike Bates asserted that according to ADEQ:

> Our "Draft Permit" is synonymous with "proposed permit" as has been the practice in the implementation of the Arkansas Title V Operating Permit since its initial approval. The 30 day public comment period and the EPA 45 day review period run concurrently.
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> As in previous permitting matters, any EPA and public comments received will be addressed in the Response to Comments document and issued with the final permit decision by ADEQ. Once a final permitting decision has been issued, our

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formally initiated as was initially the case here. This appears to unlawfully shorten the time period afford the public under the Act to review the subject permit and file a petition.

> State administrative procedures allow for parties with standing to request review (appeal) by the Arkansas Pollution Control and Ecology Commission of ADEQ's Final Permit Decision.
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> It is our understanding that the 60 day window for a person to submit a petition for objection to EPA begins upon expiration the 45 day EPA review period (in this case, December 5, 2011) - assuming that EPA does not submit an objection pursuant to APC&EC Reg. 26.605 [40 CFR 70.8 (c)].

Id. On November 22, 2011, EPA's Mr. Robinson e-mailed a response to ADEQ that disagreed with ADEQ legal position, stating:

> It is also my understanding that on an individual permit where significant changes are made that EPA can exercise it's right under 40 CFR 70.8 to review the proposed permit that ADEQ wants to issue. I'm getting questions from EPA Hq about this permit and also have Sierra Club calling me about the permit. I just want to verify ADEQ's willingness to let us review a proposed permit if significant changes are made as a result of public comment on the draft permit.

Id.

> ADEQ's Mike Bates responded the same day, asserting:
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> I don't think we would have a problem with you reviewing it, I just don't know how we could legally take any additional comments after the close of the comment period and use them as a basis for a change. Having said that, if we make significant changes to the draft due to public comment, we would have to decide if a second public comment period is necessary to truly provide for meaning public involvement. Does this help any?
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> On November 24, 2011, EPA's Jeff Robinson stated in response to that e-mail that:
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> I received feedback on Karen's response from the Office of General Counsel and Regional Counsel. The feedback stated that "when EPA approved state permitting authorities' ability to run the 30 day comment period concurrently with EPA's 45 day comment period it was historically conditioned on receiving no significant public comments (other states have similar systems). If a permitting authority receives a significant public comment during the comment period (even if in response to that comment no substantive changes are made to the draft permit), we have historically said that the permit process has to revert back to the process whereby the 45 day review period comes AFTER the close of the 30 day comment period."

> With this direction, I would like the opportunity to review the proposed permit prior to the final being issued. This is consistent with how we review permits issued concurrently in Louisiana.

Id.

After the pre-decisional unsigned final White Bluff Title V renewal permit was provided to EPA by ADEQ's Thomas Rheaume on May 18, 2012,[10] EPA's Jeff Robinson sent an e-mail on May 24, 2012 to ADEQ's Mr. Rheaume which stated:

> FYI.....since ADEQ received significant public comments on this permit, I will be talking to our Regional Counsel about treating this as our 45-day review period of the proposed permit and about re-posting to the Region 6 Air Permits website for Title V Permits to begin the 45-day clock and 60-day clock for petitions. As you are aware, we've already received a Title V petition based on the draft permit.

E-mail Chain Between EPA and ADEQ from May 18, 2012 to June 13, 2012 (Ex. 73).

ADEQ's Mr. Rheaume subsequently sent an e-mail to EPA's Mr. Robinson on June 13, 2012, noting that he had "looked on your [EPA's] website and could not find that you re-posted this. Did you change your mind? Am I looking in the wrong place?" *Id.*

This dispute between EPA and ADEQ has created uncertainty in the Title V permitting process in Arkansas which has severely prejudiced Sierra Club. Sierra Club been forced to expend the time, money and effort to prepare two petitions without knowing which one will be acted on by EPA. And, based on what is an erroneous reading of Arkansas' Title V procedural rules, ADEQ continued to revise the White Bluff Title V permit and ADEQ's final response to

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[10] *See* E-mail Chain Between EPA and ADEQ from May 18, 2012 to June 13, 2012 (e-mailing "the Response to Comments document along with a copy of the ***pre-decisional (unsigned) final permit*** which reflects revisions to the draft permit in response to comments received.") (emphasis added) (Ex. 73); *see also* May 2012 ADEQ Response to Comments at 13 (Ex. 74).

comments even after its submission in May 2012 to EPA for review.[11] This created a moving target for Sierra Club to address in its petition. Furthermore, EPA was unlawfully denied the ability to object or comment on more recent changes contained in the "final" permit but which should have been included in the "proposed" permit. *See, e.g.*, E-mail Chain Between Entergy's Attorney Chad Wood, Esq. of Gill, Elrod, Ragon, Owen & Sherman and ADEQ's Stuart Spencer, Esq. from May 16, 2012 to May 31, 2012 (coordinating a meeting on May 21, 2012, three days after the Title V permit was submitted to EPA, to discuss further potential changes to the Final White Bluff Title V renewal permit and ADEQ's Response to Comments) (Ex. 80); *see also* E-mail Chain Between ADEQ's Thomas Rheaume and Stuart Spencer, Esq., from June 25, 2012 to June 26, 2012 (Ex. 81) (in which Mr. Spencer states: "I have revised our Response to Comments document. I know that you had previously sent a rough draft to EPA for their review." and to which Mr. Rheaume responded: "What makes you think what we sent to EPA was a 'rough draft'?"). Clearly, the Response to Comments sent by ADEQ to EPA in May 2012 was a rough draft, as the final August 2012 Response to Comments has been significantly revised.

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[11] For instance, in the pre-decisional unsigned final permit submitted to EPA in May 2012, ADEQ included a condition that limited heat input to 8700 MMBtu/hr but over a new, much extended 24-hour averaging time and included related recordkeeping requirements, *see* May 2012 White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Conditions IV.37 and IV.38, at pdf 31 (Ex. 79), but those provisions have been removed from the final permit. *See* Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition IV, at pdf 32 (Ex. 72). Also, in the final Title V Renewal Permit, ADEQ substantially modified Condition IV.26 of the White Bluff Title V Renewal Permit, which provided a calculation for determining the allowable ash and sulfur content of coal combusted at the plant, without providing that change to EPA (or to the public) for review. *Compare* May 2012 White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition IV.26, at pdf 27 (Ex. 79) to Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition IV.26, at pdf 28 (Ex. 72).

Regardless of the potential existence of EPA's agreement, practice or custom, the applicable procedural rules must be followed in order to avoid situations such as the one at hand. In this instance, ADEQ failed to meet its statutory and regulatory obligations to submit a "proposed" White Bluff Title V permit for EPA review. Instead, ADEQ initially submitted a draft Title V permit to EPA on approximately October 20, 2011 and subsequently submitted what was in fact another draft Title V permit to EPA for review on May 18, 2012. This second permit was not identified by ADEQ as a proposed or as a final permit. It was dismissively designated as an "pre-decisional (unsigned) final permit," a type of permit that is not even contemplated by the applicable regulations.[12] It was later altered significantly before issuance, demonstrating, consistent with it being a "pre-decisional" permit, that it was not a version of a permit that ADEQ proposed to issue and, therefore, was not a "proposed" permit. Accordingly, Sierra Club petitions EPA to object to the Final White Bluff Title V renewal permit issued in violation of Clean Air Act 505(a) and (b), 42 U.S.C. §§ 7661d(a) and (b), 40 C.F.R. § 70.9(c)(3)(i) and (ii), and APCEC Reg. 26.603(A). Before any final Title V permit for White Bluff can be issued, EPA must ensure that ADEQ has complied with the applicable Title V procedural rules which require that ADEQ submit a "proposed" Title V renewal permit for the White Bluff plant to EPA for a formal 45-day review. 42 U.S.C. §§ 7661d(a) and (b); 40 C.F.R. § 70.9(c)(3)(i) and (ii); APCEC Reg. 26.603(A). Furthermore, to avoid similar situations in the future, Sierra Club respectfully requests that EPA develop and make publicly available a written agreement with ADEQ that

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[12] *See* May 2012 ADEQ Response to Comments at 13 ("[T]his Response to Comments document along with a copy of the ***pre-decisional (unsigned) final permit*** which reflects revisions to the draft permit in response to comments received was provided to EPA as requested on May 18, 2012.") (emphasis added) (Ex. 74).

clarifies when the proper 45-day review will start on a Title V permit issued by Arkansas, and when the public petition period will start. The current process, in which it appears EPA may require the submittal of two petitions by the public for the same permit (one on the draft permit and another on the proposed or final permit) is unduly burdensome to the public and is also inconsistent with the public petition provisions of the Clean Air Act.

Issue #2: The Administrator Must Object to the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) Because it Unlawfully Removes, Relaxes, and/or Revises Federally Enforceable Limitations on Heat Input and the Coal Burning Capacity of the Boilers and Allows for an Increase in the Amount of Coal Burned at Each White Bluff Boiler Without Subjecting the Change to New Source Review.

In its October 20, 2009 Title V Permit Renewal Application at 1 (Ex. 1), EAI asked ADEQ to increase "the assumed maximum heat input" for the White Bluff Units 1 and 2 boilers from 8700 MMBtu/hr to 8950 Btu/hr "based on historical data."[13] EAI also stated in its permit application a maximum production/operation rate of 540 tons of coal per hour for each White Bluff Unit 1 and 2 boilers, *id.*, which reflects an increase of 15 tons per hour from the prior Title

[13] This contention appears to be misleading at best, as Entergy had initially requested this change to allow, after planned turbine upgrades, for a 2.9% increase in the coal feed rate for Units 1 and 2 and an increase of up to 3% in throughput for White Bluff plant's coal handling and storage facilities which Entergy indicated would allow the Units to recover lost generating capacity stemming from parasitic loads associated with the dry scrubber and baghouse that Entergy planned to install at White Bluff to comply with anticipated BART requirements. *See* January 2009 PSD permit application which was submitted to ADEQ by EAI via a February 4, 2009 letter at 2-7 (Ex. 10); January 2009 Application for Permit to Construct Entergy White Bluff Units 1 & 2 Air Pollution Control Project at 2-7, pdf 18 (Ex. 64); October 8, 2009 Letter from Entergy to ADEQ (Ex. 65); Marked-up Pages of PSD Application at 4-1 (Ex. 66). Although Entergy subsequently changed course and asserted it did not need to increase permitted heat input capacity to recover the parasitic losses from the BART controls, it nonetheless requested an increase in permitted heat input capacity from 8700 MMBtu/hr to 8950 MMBtu/hr., *see* Marked-up Pages of PSD Application at 4-1 (Ex. 66), belatedly arguing that this was justified based on historical data. *Id.* Curiously, Energy did not argue that its accompanying request for an increase in the tons per hour limit of coal burned – a parameter closely associated with heat input – was justified by "historical data."

V permit applications for White Bluff Units 1 and 2. *See, e.g.*, February 2006 Emission Rate Tables for SN-01 and SN-02, as corrected in a March 2, 2006 e-mail from George Johnson, EAI, to Ann Sudmeyer, ADEQ at 2-3 (Ex. 3). In its October 20, 2009 Title V permit renewal application, Entergy claimed that "[a]nnual emissions will not increase due to the permit limitation of 9.2 million tons of coal per twelve month period" pursuant to Condition VI.14[14] in the Pre-Existing White Bluff Title V Permit (No. 0263- AOP-R6) at 49, pdf 53 (Ex. 30). *See* October 20, 2009 White Bluff Title V Permit Renewal Application at 1 (Ex. 1). However, the facility-wide 12 month limit on coal throughput at the White Bluff units provide no lawfully cognizable assurance that emissions will not increase sufficiently to trigger the application of the PSD permitting requirements as a result of EAI burning 15 more tons of coal per hour at each White Bluff unit.

The permit application submitted by Entergy on October 20, 2009 identifies the heat input capacity of SN-01 and SN-02, which are the emission point numbers for the Unit 1 and Unit 2 boilers, respectively, as 8950 MMBtu/hr. *See* October 20, 2009 White Bluff Title V Renewal Application, Appendix A, Emission Unit Forms for SN-01 and SN-02 at pdf 55, pdf 59 (Ex. 1). The company's permit application also identified the maximum production/operation rate of each boiler as 540 tons of coal per hour. *Id.* These reflect increases of about 3% in both

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[14] In the October 2011 Draft White Bluff Title V Renewal Permit (No. 0263-AOP-R7) at Specific Condition VI, Plantwide Conditions (Ex. 63), ADEQ deleted a provision establishing an plantwide 9.2 million tons per year limit on the amount of coal combusted, which Entergy sought to rely on to justify its original request for a heat input increase. However, in the permit submitted to EPA on May 18, 2012 and the Final White Bluff Title V Renewal Permit, that 9.2 million ton per year limit was been added back in. May 2012 White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition VI.15, at pdf 58 (Ex. 79); Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition VI.15 at pdf 59 (Ex. 72).

heat input capacity and maximum hourly coal throughput per boiler over the heat input capacity and maximum coal throughput rates identified in Entergy's last Title V Permit Modification Application that included forms for SN-01 and SN-01 -- that is, EAI's February 2006 Permit Application that preceded Permit No. 0263-AOP-R4. In the February 2006 Permit Application, EAI identified the heat input capacity of each White Bluff boiler as 8700 MMBtu/hr and identified the maximum coal throughput as 525 tons per hour per boiler. *See* February 2006 Emission Rate Tables for SN-01 and SN-02, as corrected in a March 2, 2006 e-mail from George Johnson, EAI, to Ann Sudmeyer, ADEQ at 2-3 (Ex. 3). In fact, EAI's 1996 Permit Application for its initial Title V permit also indicated that the heat input capacity and maximum operation rate of SN-01 and SN-02 was 8700 MMBtu/hr and 525 tons of coal per hour for each boiler. *See* April 22, 1996 White Bluff Permit Application, Emission Rate Tables for SN-01 and SN-02, at pdf 7, pdf 9 (Ex. 4). Entergy is required to certify to the truthfulness, accuracy and completeness of its permit applications pursuant to APCEC Reg. 26.410, and the company has done so in its Title V permit applications. *See, e.g.*, April 22, 1996 White Bluff Permit Application, Certification of Application, at pdf 5 (Ex. 4).

In the October 2011 draft Title V renewal permit for White Bluff, ADEQ proposed changing the language of the enforceable limitation on the heat input capacity of the White Bluff boilers which, in the previously effective Title V permit, limited the maximum heat input capacity of the White Bluff boilers to 8700 MMBtu/hr each. *See* Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6) at 16, pdf 20 (Ex. 30). Specifically, ADEQ proposed to alter the language of the permit condition in Section IV of the permit by adding the word "approximately" before the listed 8700 million BTU per hour heat input capacity of the boilers, which would have

had the effect of making the 8700 MMBtu/hr heat input capacity an unenforceable requirement of the permit. *See* Draft White Bluff Title V Renewal Permit (No. 0263-AOP-R7) at 19 (Ex. 63). ADEQ also proposed to delete the permit condition that limited the total amount of coal burned per twelve month period to 9.2 million tons of coal, a permit condition that has existed in the White Bluff permit since a permit issued in 1998.[15] *See* Permit No. 263-AOP-R1, Condition IV.8 at 31 (Ex. 5); *see also* Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6), Condition VI.14, at 49, pdf 53 (Ex. 30).

Subsequently, in the version of the Title V renewal permit submitted to EPA on May 18, 2012, ADEQ retained the existing permit condition limiting the heat input capacity of the boilers to 8700 MMBtu/hr.[16] May 2012 White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition IV, at pdf 19 (Ex. 79). However, in response to comments submitted by Sierra Club that ADEQ cannot allow an increase in the allowable heat input capacity of the White Bluff units without evaluating the allowed increase in emissions for applicability to prevention of significant deterioration ("PSD") permitting requirements (November 23, 2011 Letter from Sierra Club to ADEQ at 3, 16-20 (Ex. 67), ADEQ argued that the heat input limit was not a specifically enforceable requirement because it was allegedly only included in "descriptive parts" of the White Bluff Title V permit and in permits (*i.e.*, past Title V permits and construction permits

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[15] In the most recent ADEQ Response to Comments, ADEQ states that this limit was removed "in error" without providing any explanation as to why ADEQ initially believed it could remove this limit or any description of what the error actually was that led to it being removed from the permit in the first place. August 2012 ADEQ Final Response to Comments at 6 (Ex. 76).

[16] ADEQ did remove the qualifier "approximately" from the heat input limit that it had included in the draft permit. May 2012 White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition IV, at pdf 19 (Ex. 79).

issued under the SIP). May 2012 ADEQ Response to Comments at 2-3 (Ex. 74). After drawing this conclusion, ADEQ went on in circular fashion to determine that it was in fact necessary for the White Bluff Title V permit to contain a 8700 MMBtu/hr heat input limit for the purpose of assuring compliance with "particulate emission rates and particulate National Ambient Air Quality Standard (hereinafter "NAAQS")." *Id.* at 3. And it took it upon itself to incorporate a new 8700 MMBtu/hr heat input limit into the White Bluff Title V permit, albeit one with a far more relaxed twenty-four (24) hr. averaging period and newly created recordkeeping requirements.[17] *See* May 2012 White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Conditions IV.37 - IV.38, at pdf 31 (Ex. 79). The justification given by ADEQ for taking this counterintuitive step was that the 8700 MMBtu/hr heat input limit was an integral component of the permit's structure and had been relied on to calculate emissions and emissions increases or

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[17] Specifically, ADEQ asserted in its May 2012 Response to Comments that:

> Entergy has in the past used the 8700 MMBTU/hr rating to calculate emissions and emission increases/changes. ***On that issue, the limit needs to be included in the permit*** until such time as an application that addresses all issues with an increase is submitted and approved. The limit will be averaged on a 24 hour basis to assure compliance with the particulate emission rates and particulate National Ambient Air Quality Standard (hereinafter "NAAQS").

May 2012 ADEQ Response to Comments at 3 (Ex. 74) (emphasis added). Sierra Club agrees to an extent with ADEQ's concession that the 8700 MMBtu/hr heat input limit "needs to be included in the permit . . . ." *See generally In the Matter of Alliant Energy - WPL Edgewater Generating Station*, Permit No. 460033090-P20, Petition Number V -2009-02, Order at 5 (Adm'r August 17, 2010) (explaining that maximum heat input limits, even if they are only included in permit applications, should be treated as permit requirements where, as here, "the integrity of [a] permits pounds per hour emission limits . . . depend upon heat input . . . .") (Ex. 84). However, what Sierra Club recognizes and ADEQ has consistently ignored is that the "necessary" heat input limit – the longstanding 8700 MMBtu/hr heat input condition, which is inherently part of the architecture of the Title V permit and provides the basis for a number of pounds per hour emission limits – has existed in White Bluff permits as far back as 1991. *See* Permit No. 0263-AR-1 at pdf 5 and pdf 7 (Ex. 6).

changes.[18]

However, on August 9, 2012, when the Final White Bluff Title V Renewal Permit and new associated Response to Comments were issued, it was revealed that ADEQ had performed yet another about face. Specifically, ADEQ removed the new permit condition that it had included in its May 2012 pre-decisional final permit submitted to EPA that would have imposed a limit on heat input of 8700 MMBtu/hr which relied on a 24-hour averaging time. *See* Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) (no longer includes the 24-hour average limit on heat input of the White Bluff boilers that had been included for the first time in the May 2012 version of the permit submitted to EPA) (Ex. 72).[19] As in the May 2012 version of the permit, ADEQ maintained the 8700 MMBtu/hr heat input limit from the prior permits without including the qualifier "approximately," but ADEQ claimed for a number of unconvincing reasons that the pre-existing 8700 MMBtu/hr heat input limit was not federally enforceable. *Id.*, Condition IV, at pdf 20; August 2012 ADEQ Final Response to Comments at pdf 2-6 (Ex. 76). Notably, ADEQ asserted for the first time that because of alleged variability in the heat content of coal, a given plant's "final performance" so far as its design BTU rating is

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[18] Sierra Club has consistently argued that this fact bolsters its argument that the original 8700 MMBtu/hr provision in the White Bluff Title V permit (and in other SIP-approved permits) is a federally enforceable permit condition.

[19] If ADEQ had included the 24-hour averaging period for the heat input limit as was reflected in the May 2012 version of the permit, it would have allowed for much more than a "slight" increase in heat input. *See* ADEQ's Response to Comments at 2 ("Plants are generally designed around a given BTU rating, but these designs can in the end ***vary slightly. Though a plant may be designed as 8700 MMBTU per hour, the final performance of the plant may vary.***") (emphasis added). To the contrary, for short periods of time, the White Bluff units would have been permitted to operate at a heat input rate far higher than the 2009 requested increase to 8950 MMBtu/hr maximum heat input. *See* 2009 Title V Permit Renewal Application. at 1 (Ex. 1).

concerned can "vary slightly" and, for this reason, ADEQ argued that changes in heat input should not be viewed as "a physical change in the method of operation."[20] August 2012 ADEQ Final Response to Comments at pdf 3 (Ex. 76).

Additionally, the May 18, 2012 version of the Title V renewal permit submitted to EPA subtly authorized Entergy's requested heat input capacity increase without explicitly changing the stated maximum heat input. It did so by granting Entergy the authority "to construct, operate, and maintain the equipment and/or control apparatus ***as set forth in your application*** initially received on 10/20/2009." Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) at 1 (emphasis added) (Ex. 72); *see also* Draft White Bluff Title V Renewal Permit (No. 0263-AOP-R7) at 1 (Ex. 63); when the Title V permit application listed the heat input capacity of the White Bluff Units 1 and 2 boilers as 8950 MMBtu/hr (instead of 8700 MMBtu/hr) and identified the maximum coal throughput as 540 tons per hour (instead of 525 tons per hour).

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[20] This appears to reflects a legal error on ADEQ's part that colors ADEQ's analysis of the relevant PSD issues. The definition of "major modification" under the federal regulations which have been adopted as part of the Arkansas SIP has at all relevant times included two separate threshold events which may act as a trigger for PSD review, either (1) a physical change or (2) a change in the method of operation. 40 C.F.R. § 52.21(b)(2)(i)(1994)(Older SIP-approved PSD regulations); 40 C.F.R. § 52.21(b)(2)(i) (2007)(current SIP-approved PSD regulations). ADEQ appears to have misconstrued this regulatory definition, combining the two independent triggers for PSD review into one novel and narrow event, a "physical change in the method of operation," and has unlawfully applied its erroneous definition of "major modification" in this instance. *See* August 2012 ADEQ Final Response to Comments at pdf 3 (Ex. 76); *see also* Final White Bluff Title V Renewal Permit (No. 0263- AOP-R7), Section III, Permit History at pdf 17 ("263-AOP-RO was the first operating air permit issued to Entergy-Arkansas, Inc. - White Bluff Steam Electric Station under Regulation 26. ***No physical changes in the method of operation*** at the facility occurred prompting this permit issuance.") (emphasis added) (Ex. 72). ADEQ's conflated definition of the term "major modification" is inconsistent with the plain language of the pertinent regulations and, therefore, it is unlawful. Significantly, ADEQ's definition drastically narrows the scope of what may constitute a "physical change" and reads "changes in the method of operation" out of the definition of "major modification" entirely. For this reason, ADEQ's analysis of all the NSR/PSD issues is suspect.

By approving all the substantial permit changes discussed above, the final White Bluff Title V renewal permit (and the prior versions of that permit) effectively allows for an increase in the heat input capacity and coal throughput of the White Bluff boilers above what is and has historically been allowed under the terms of the Title V permits for White Bluff dating back to the first operating permit issued for White Bluff in 1998, as well as dating back to a permit issued under the State Implementation Plan ("SIP") for White Bluff in 1991. *See* Permit No. 0263-AR-1 at pdf 5, pdf 7 (Ex. 6); Permit No. 263-AOP-R1 at 1, 8, 31 (Ex. 5); April 22, 1996 White Bluff Permit Application, Emission Rate Tables for SN-01 and SN-02, at pdf 7, pdf 9 (Ex. 4); Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6) at 16, pdf 20 and 49, pdf 53 (Ex. 30). An increase in heat input capacity and coal burning capacity of the White Bluff boilers above the federally enforceable capacity limitations of the immediately prior (and past) White Bluff permits is a change in the method of operation under the Clean Air Act's PSD program and would clearly allow for an increase in actual emissions due to the increased heat input/burning of more coal in the boilers. Yet, neither Entergy nor ADEQ reviewed this significant increase in coal-burning capacity of the White Bluff boilers to determine if significant emission increases and significant net emissions increases of any regulated new source review pollutant would be projected with the increase in allowable coal-burning capacity of the White Bluff boilers, which would require, among other things, the issuance of a PSD permit including the application of best available control technology ("BACT"). As Sierra Club demonstrates below, the increase in heat input capacity and coal burned should have been projected to result in significant emission increases of sulfur dioxide ("SO2"), nitrogen oxides ("NOx"), PM2.5, and likely greenhouse gases at each White Bluff unit, among other pollutants.

Consequently, Sierra Club is petitioning EPA to object to the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7). Specifically, Sierra Club requests that EPA object to the permit because it unlawfully removes, relaxes, and/or revises the enforceable restriction on heat input and coal burning capacity of the White Bluff boilers and because it allows for an increase in heat input and the hourly coal throughput of the White Bluff boilers without the issuance of a PSD permit and application of BACT requirements. We request that EPA order ADEQ to either (1) retain the federally enforceable 8700 MMBtu/hr heat input capacity limit on the White Bluff boilers and specifically prohibit Entergy from increasing the maximum heat input and coal throughput of the White Bluff boilers above the 8700 MMBtu/hr and 525 tons of coal per hour levels as requested in Entergy's October 2009 permit application or (2) require ADEQ to issue a PSD permit and incorporate BACT and other applicable PSD requirements for those pollutants for which the heat input capacity increase would be projected to result in a significant emission increase and a significant net emissions increase, which Sierra Club contends would at least include SO2, NOx, PM2.5 and also likely greenhouse gases. Sierra Club raised this issue in its November 23, 2011 comment letter to ADEQ. *See* 11/23/11 Sierra Club's Comments on the Draft Title V Renewal Permit for the Entergy Arkansas White Bluff Plant (Draft Permit No. 0263-AOP-R7) at 2-20 (Ex. 67). The reasons why the changes to the White Bluff Title V permit do not ensure compliance with all applicable requirements are summarized below.

A. <u>An Increase in the Operating Capacity Is Considered a Physical Change or Change in the Method of Operation Under the PSD Permitting Regulations that Must Be Reviewed for Applicability to PSD Permitting.</u>

Under the federal PSD regulations which have been incorporated by reference into Arkansas Reg. 19.904(A) and approved by EPA as part of the Arkansas SIP (at 40 C.F.R. §

52.170(c)), any existing source that undertakes a major modification must first obtain a PSD permit and meet all PSD permitting requirements including application of best available control technology ("BACT"). *See* 40 C.F.R. § 52.21(a)(2)(ii) and (iii). A "major modification" is defined 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 (as defined in [40 C.F.R. 52.21(b)(40)]) of a regulated NSR pollutant (as defined in [40 C.F.R. 52.21 (b)(50)]); and a significant net emissions increase of that pollutant from the major stationary source.

40 C.F.R. § 52.21(b)(2)(i). The definition of "major modification" excludes the following from being considered a "physical change or change in the method of operation:"

> (f) An increase in the hours of operation or in the production rate, 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)(f).

ADEQ relies on this exemption to justify allowing the White Bluff units to operate at higher hourly heat input capacities and higher hourly coal feed rates than previously permitted, claiming that there were no federally enforceable limits on hourly heat input capacity or on hourly coal throughput (other than an annual limit on the plantwide coal throughput per year) applicable to the White Bluff Units. August 2012 ADEQ Final Response to Comments at 3-4 (Ex. 76). However, ADEQ is incorrect: there are and have been federally enforceable limits on hourly heat input capacity and on hourly coal throughput at the White Bluff units.

B. The Heat Input Capacity and Coal Throughput Limits of the Permit Are Federally Enforceable Limits on the Production Rate of the White Bluff Units.

The maximum production rate of the White Bluff boilers is prohibited under federally enforceable permit conditions of the prior White Bluff Title V Permit (No. 0263-AOP-R6)[21] and under a 1991 construction permit issued by ADEQ under the Arkansas SIP, Permit No. 0263-AR-1 (Ex. 6). The conditions of the previous White Bluff Title V Permit (No. 0263-AOP-R6) that limit the maximum production rate of the White Bluff units include: (1) Section IV of the permit which identified the heat input capacity of the boilers as 8700 MMBtu; (2) Condition VI.14 of the White Buff Title V Permit (No. 0263-AOP-R6), which limits total coal throughput of the plant; and (3) the cover page of that permit which authorizes operation of the White Bluff facility in accordance with the permit application, which at that time identified the heat input capacity of the boilers as 8700 MMBtu/hr and identified the maximum coal throughput of each boiler as 525 tons per hour. *See* White Bluff Permit Application Forms for SN-01 and SN-02, submitted by Entergy to ADEQ in a March 2, 2006 e-mail (Ex. 3).

The underlying construction permit, White Bluff Permit (No. 263-AR-1) (Ex. 6) which was issued April 9, 1991 by ADEQ under the "Regulations of the Arkansas Plan of Implementation for Air Pollution Control and the Arkansas Air Pollution Control Code,"[22]

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[21] Permit No. 0263-AOP-R6 had an expiration date of April 27, 2010, but Arkansas Reg. 26.406 provides that, if a timely and complete renewal application has been received by ADEQ, "the existing permit shall remain in effect until the Department takes final action on the renewal application." According to ADEQ's website, ADEQ found the White Bluff Title V renewal application complete on October 20, 2009. Accordingly, based on ADEQ's determination, Permit No. 0263-AOP-R6 was still in effect until August 9, 2012.

[22] The "Regulations of the Arkansas Plan of Implementation for Air Pollution Control and the Arkansas Air Pollution Control Code" have been approved as part of the Arkansas SIP since October 5, 1976 (41 Fed.Reg. 43904); 40 C.F.R. §51.170(c)(4). Revisions were approved on

limited the maximum production rate of the White Bluff boilers as well. The introductory paragraph of this permit states that "[t]his permit is your authority to construct, operate and/or maintain the equipment and/or facility in the manner set forth in the Department's summary report and your application dated January 19, 1991." *Id.* at 2. The Department's Summary Report states "[b]oth units burn pulverized sub-bituminous coal at a peak rate of 8.7 billion BTU/hr each." *Id.* at 4. The Department's Summary Report also states that the units are subject to the New Source Performance Standards, Subpart D, and the Summary Report explains that those NSPS limits are 0.1 lb.MMBtu for PM, 20% opacity, 1.2 lb/MMBtu for SO2, and 0.7 lb/MMBtu for NOx. *Id.* Further, Specific Condition 1 of the Summary Report states that emissions shall not exceed the limits listed in Table 1. *Id.* Table 1 of that permit is the "Allowable Emissions Summary Sheet" and the heat input capacity of 8700 MMBtu/hr per unit is included in that table.[23] *Id.* at 6. Table 1 also identifies limits on particles, PM10, SO2, NOx, CO and VOCs in pounds per hour. A review of the pound per hour emission rates for

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February 23, 1989 (54 Fed.Reg. 07764); 40 C.F.R. §52.170(c)(4), and on May 1, 1989 (54 Fed.Reg. 18494); 40 C.F.R. §52.170(c)(27). It appears the version of these regulations last approved into the Arkansas SIP before the 1991 Permit No. 263-AR-1 was issued is posted on EPA's Arkansas SIP regulation website at http://yosemite.epa.gov/r6/Sip0304.nsf/home!OpenView&Start=1&Count=30&Expand=2.4#2.4 (under Arkansas SIP Regulations: SIP effective until 2000.11.15 (November 15, 2000)).

[23]There is no question that the 8700 MMBtu/hr heat input capacity listed in Table 1 is an emission limitation, as the "Regulations of the Arkansas Plan of Implementation for Air Pollution Control and the Arkansas Air Pollution Control Code" define "emission limitation" as including limitations on fuel specifications and on operation procedures. *See* Section 3(w) of the "Regulations of the Arkansas Plan of Implementation for Air Pollution Control and the Arkansas Air Pollution Control Code" as in effect at the time of issuance of Permit No. 263-AR-1, available on EPA's Arkansas SIP regulation website atosemite.epa.gov/r6/Sip0304.nsf/dc994a1edbcf32c08625651c00552ed8/c9c963595847af5086256984007cf30d!OpenDocument.

particulates, SO2 and NOx reveals that the limits are based on the NSPS standard multiplied by the allowable heat input capacity of 8700 MMBtu/hr, *e.g.*, the SO2 limit is 10440 pounds per hour which equals 1.2 lb/MMBtu multiplied by 8700 MMBtu/hr.

EPA has clearly stated that Title V permits may not supersede SIP construction permits. May 20, 1999 Letter from EPA to Robert Hodanbosi, Enclosure A at pdf 4 (Ex. 82). All provisions in permits issued under a SIP-approved permitting program, including the permit provisions discussed above which restrict the White Bluff units to a heat input capacity of 8700 MMBtu/hour, are federally enforceable "applicable requirements" which must be included in Title V permits. Clean Air Act § 504(a), 42 U.S.C. 7661c; 40 C.F.R § 70.2; 40 C.F.R. § 52.23. So too are the provisions of prior Title V permits, unless those requirements are expressly designated as state-only requirements, which was not done in this instance. *See* 40 C.F.R. § 70.6(b)(2) ("the permitting authority shall specifically designate as not being federally enforceable under the Act any terms and conditions included in the permit that are not required under the Act or under any of its applicable requirements."); APCEC 26.702(B). Accordingly, for all of the above stated reasons, the increase in heat input capacity and hourly coal throughput that ADEQ has allowed in the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) is unlawful. Such an increase in coal burning capacity cannot be authorized pursuant to 40 C.F.R. § 52.21(b)(2)(iii)(f) without an evaluation of the change in the method of operation at the White Bluff source for PSD applicability.[24]

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[24] Sierra Club raised this issue in its November 23, 2011 comment letter to ADEQ on the draft White Bluff Title V renewal permit. *See* 11/23/11 Sierra Club's Comments on the Draft Title V Renewal Permit for the Entergy Arkansas White Bluff Plant (Draft Permit No. 0263-AOP-R7) at 5-12 (Ex. 67).

1. Any Argument That the Heat Input Capacity Limits of the White Bluff Permits Are Purely Descriptive and Unenforceable Lacks Merit.

The heat input capacities spelled out in Condition IV of the prior White Bluff Title V Permit (No. 0263-AOP-R6) and in Permit No. 0263-AR-1 are without question enforceable emission limits.

a. *White Bluff Title V Permit (No. 0263-AOP-R6) Has Enforceable Limits on Heat Input Capacity of the White Bluff Boilers.*

There are different sections of the prior White Bluff Title V Permit (No. 0263- AOP- R6) which serve different functions. The heat input capacity of the existing White Bluff Title V permit is set forth in Section IV of the permit which is entitled "Specific Conditions." Under the subheading "Source Description" in Section IV, the permit states that the boilers are 8700 MMBtu/hr boilers. Pre-Existing White Bluff Title V Permit (No. 0263- AOP- R6) at pdf 20 (Ex. 30). The "Source Description" in Section IV also spells out the types of coal the White Bluff units are authorized to burn (subbituminous and bituminous), the startup fuels the boilers are allowed to use (No. 2 Fuel Oil or Bio-diesel), the pollution controls the units operate with (electrostatic precipitators and low sulfur coal), and the federal NSPS regulations that the boilers are subject to (NSPS Subpart D). *Id.* All these provisions set forth in Section IV are "Specific Conditions" - *i.e.*, conditions of the permit that govern operation of the White Bluff boilers -- and they are enforceable as such. In Section II of the prior permit, there is, *inter alia*, a "Summary of Permit Activity," "Process Description," "Regulations," and an "Emissions Summary." *Id.* at 9-16. Unlike the requirements set forth in Section IV, the information provided in Section II's Process Description and Emissions Summary is purely descriptive and the language of the permit makes clear that these provisions are not enforceable parts of the permit. The fact that the heat

input capacity limit is set forth in Section IV's Specific Conditions instead of in Section II signifies that it was intended to be an enforceable limitation that governs the operation of White Bluff's boilers.[25]

Moreover, White Bluff Title V Permit (No. 0263-AOP-R6) makes clear that all terms and conditions of the permit are enforceable unless otherwise specified. Specifically, Condition VII.18 of the permit states that:

> The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements.

Id. at 55, pdf 58 (Ex. 30). ADEQ has failed to identify the 8700 MMBtu/hr capacity of the White Bluff boilers in Section IV of the recently-issued Title V renewal permit or in prior Title V permits to be federally unenforceable, although ADEQ now claims that the 8700 MMBtu/hr heat input capacity is not enforceable in its August 2012 Final Response to Comments for the recently-issued White Bluff Title V Permit (No. 0263-AOP-R7). August 2012 ADEQ Final Response to Comments at 3-6 (Ex. 76).

Not only is the heat input capacity identified as a specific condition of White Bluff Title V Permit (No. 0263-AOP-R6) in Section IV, but that permit also includes provisions requiring Entergy to measure and record hourly heat input to each White Bluff boiler. The designation of heat input limit as 8700MMBtu/***hour*** establishes an hourly averaging time for this limit which is consistent with all the other specific compliance determination requirements. Condition IV.23 of

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[25] These same textual/structural arguments apply equally to the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) (Ex. 72).

the Permit 0263-AOP-R6 required Entergy to determine and record the heat input to each White Bluff boiler (SN-01 and SN-02) "for every hour or part of an hour any fuel is combusted following the procedures in Appendix F of 40 CFR Part 75," *Id.* at pdf 28 (Ex. 30), and that condition has been retained in the recently issued Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition IV.23., at pdf 28 (Ex. 72). Condition IV.20 of the Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6) (and the Final White Bluff Title V Permit (No. 0263-AOP-R7) requires that boilers SN-01 and SN-02 shall comply with the acid rain program, including 40 C. F. R. Parts 75. Draft White Bluff Title V Renewal Permit (No. 0263-AOP-R6), Condition IV.20., at pdf 28 (Ex. 30); *see also* Final White Bluff Title V Renewal Permit, Condition IV.20, at pdf 27 (Ex. 72). 40 C.F.R. § 75.16(e) includes procedures for calculating heat input rate from monitors for flow rate and diluent, which are required to be monitored continuously pursuant to 40 C.F.R. § 75.10(a)(3). The hourly data is required to be submitted to EPA pursuant to 40 C.F.R. § 75.64 and Condition IV. 21 of the Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6) (and the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7)). Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6), Condition IV.21, at 28; Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition IV.21, at pdf 27 (Ex. 72). Such data is readily accessible by ADEQ as well as the public on EPA's Clean Air Markets Database website at http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard. Thus, the Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6) includes an averaging time and all the test methods, recordkeeping and reporting requirements for hourly heat input to the boiler necessary to ensure that the heat input capacity limits in Section IV of that

permit is practically enforceable based on the terms of the permit.[26]

Other conditions of the Pre-Existing White Bluff Title V Permit also limit the heat input capacity of the boilers to 8700 MMBtu/hr. First, the cover page of White Bluff Title V Permit (No. 0263-AOP-R6) states "[t]his permit authorizes the above referenced permittee to install, operate, and maintain the equipment and emission units described in the permit application and on the following pages." Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6) at 1, pdf 5 (Ex. 30). Entergy has consistently identified the heat input capacity of the White Bluff boilers in every subsequent Title V permit application as 8700 MMBtu/hr, until the October 20, 2009 permit application.[27] Second, Condition VI.5 of the prior permit states "[t]he permittee must operate the equipment, control apparatus and emissions monitoring equipment within the design limitations." *Id.* at Condition VI.5, at 47, pdf 51.

Third, Permit Condition IV.26 of the Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6) express relied on and incorporated the 8700 MMBtu/hr heat input capacity of the boilers into an equation that defines when sulfur and ash content of the coal burned can exceed the specified limits of the permit. Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6), Condition IV.26, at pdf 29 (Ex. 30). ADEQ acknowledged in its August 2012 Final Response to Comments at 4 that this permit condition was based on the 8700 heat input capacity of the White Bluff boilers. Nonetheless, ADEQ revised this same equation in the Final White Bluff Title V Renewal Permit to reflect the maximum heat input capacity of 8950 MMBtu/hr initially

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[26] And the same is true for the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7).

[27] *See, e.g.*, March 2006 White Bluff Permit Application at 2-3 (Ex. 3); 1991 White Bluff Permit Application, Table 1, at 1, pdf 8 (Ex. 8).

requested by EAI, which effectively relaxes the prior maximum heat input limit. Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition 26, at pdf 28 (Ex. 72)

Furthermore, the Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6) relies on the permitted heat input capacity of the White Bluff units to determine the units' compliance with the lb/hr limits of the White Bluff permit. Specifically, Specific Conditions 24 and 25 of Section IV of the Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6) (and the Final White Bluff Renewal Permit (No. 0263-AOP-R7)) require that emissions testing of the White Bluff boilers for carbon monoxide ("CO"), PM and PM10 be conducted while the units are operating at 90% or greater capacity and that the emission results must be "extrapolated to correlate with 100% of the ***permitted capacity*** to determine compliance." Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6), Conditions IV.24 and IV.25, at pdf 28 (Ex. 30) (emphasis added); *see also* Final White Bluff Title V Permit (No. 0263-AOP-R7), Conditions IV.24 and IV.25, at pdf 28 (Ex. 72). The White Bluff permit specifically refers to the "permitted capacity" of the White Bluff boilers and relies on that permitted capacity to determine compliance with the emission limits. Therefore, the permitted capacity of the White Bluff boilers must itself be maintained as an enforceable permit condition of the permit. If there was no enforceable heat input capacity limit for the boilers, then the CO, PM and PM10 lb/hr emission rates would not be enforceable under the terms of the White Bluff permit.

In its Final Response to Comments at pdf 4-5 (Ex. 76), ADEQ claims that "permitted capacity" is "interpreted" to mean maximum capacity in terms of megawatt output and not the heat input capacity. However, this post-hoc rationalization is not due any deference since ADEQ's so-called interpretation is inconsistent with the permit's language and its overall

structure. Because the permit does not include any limits on the megawatt capacity of the White Bluff units, ADEQ's position does not reflect a plausible and/or permissible construction of the permit condition.

In Section II of White Bluff Permit (No. 0263-AOP-R6) under "Process Description," the plant is identified as having a "total capacity of approximately 1690 megawatts (MW)," and this language also exists in the recently issued Permit No. 0263-AOP-R7. Permit No. 0263-AOP-R6, Section II., at 5 (Ex. 2); Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Section II, at 5 (Ex. 72). This does not equate to a "permitted capacity" for each unit, which would be necessary to properly implement the testing requirements of Conditions IV.24 and IV.25 of the White Bluff Title V Permit (in both Permit No. 0263-AOP-R6 and No. 0263-AOP-R7). Instead, these conditions had to be tied to the permitted heat input capacity of each White Bluff unit - *i.e.*, 8700 MMBtu/hr pursuant to Section IV of the White Bluff Title V Permit (No. 0263-AOP-R6). Further, ADEQ's Title V permit application forms do not even ask for megawatt generating capacity. Instead, the ADEQ permit application forms ask for heat input capacity. March 2, 2006 White Bluff Permit Application Forms at pdf 2 and pdf 3 (Ex. 3); October 20, 2009 White Bluff Permit Application Forms at pdf 57 and 59 (Ex. 1). Given that heat input, which essentially reflects how much coal is being burned, is directly related to how much air pollution is emitted, it makes sense that the ADEQ permit application forms only request heat input capacity and that the Title V permit only limits heat input capacity. It also makes sense that the PM and CO testing requirements of Conditions IV.24 and IV.25 of the White Bluff Title V Permit (in both Permit No. 0263-AOP-R6 and No. 0263-AOP-R7) are to be based on the units

each operating at 90% or greater of permitted *heat input* capacity.[28]

For all of the reasons explained above, the heat input capacity of the boilers specified in Condition IV of the prior White Bluff Title V permit (0263-AOP-R6) is an enforceable requirement of the permit that ADEQ has now relaxed by approving Entergy's October 20, 2009 Title V renewal permit application and by claiming the heat input capacity limits of Condition IV are unenforceable.

b. *Permit No. 263-AR-1 Issued Under the Arkansas SIP Also Has Enforceable Limits on Heat Input Capacity of the Boilers.*

In 1991, ADEQ issued a permit under the Arkansas SIP for White Bluff that also limited heat input capacity of the White Bluff Units 1 and 2 boilers to 8700 MMBtu/hr. Specifically, Permit No. 263-AR-1 states: "This permit is your authority to construct, ***operate*** and/or maintain ***the equipment and/or facility in the manner as set forth in the Department's summary report*** and your application dated January 19, 1991." Permit No. 0263-AR-1 at 1(emphasis added) (Ex. 6). The Summary Report states that both White Bluff units "burn sub-bituminous coal ***at a peak rate of 8.7 billion BTU/hr each***." *Id.* at 4 (emphasis added). The Department's Summary Report also states that the units are subject to the New Source Performance Standards, Subpart D, and the Summary Report explains that those NSPS limits are 0.1 lb/MMBtu for PM, 20%

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[28] The Pre-Existing Title V permit, as well as the Final White Bluff Title V renewal permit, also require Entergy to obtain approval from ADEQ before exceeding a throughput requirement, an emission rate in the permit such as the heat input limit, or any other limit in the permit. *See* Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6), Condition VIII.25, at pdf 61 (Ex. 30); *see also* Draft White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition VIII.25, at 65 (Ex. 63), Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition VIII.25, at pdf 67 (Ex. 72). Clearly, ADEQ also intended for coal throughput requirements as well as other limits in the permit along with emission rates limits to be permanent and enforceable requirements that could not be exceeded without ADEQ approval.

opacity, 1.2 lb/MMBtu for SO2, and 0.7 lb/MMBtu for NOx. *Id.* Further, Specific Condition 1 of the Summary Report states that emissions shall not exceed the limits listed in Table 1. *Id.* Table 1 of that permit is the "Allowable Emissions Summary Sheet" and the heat input capacity of 8700 MMBtu/hr per unit is included in that table. *Id.* at 6. Table 1 also identifies limits on particles, PM10, SO2, NOx, CO and VOCs in pounds per hour. A review of the pound per hour emission rates for particulates, SO2 and NOx reveals that the limits are based on the NSPS standard multiplied by the allowable heat input capacity, *e.g.*, the SO2 limit is 10440 pounds per hour which equals 1.2 lb/MMBtu multiplied by 8700 MMBtu/hr. In addition, the January 19, 1991 permit application submitted for this permit, which the first page of the 1991 permit, including Condition 2, requires that the facility be operated in compliance with, lists the "Boiler Capacity" of White Bluff Units 1 and 2 as 8700 MMBtu/hour. *See* January 1991 White Bluff Permit Application, at Table 1 (Dated December 17, 1990) at 1-2, pdf 8-9 (Ex. 8). Thus, the pound per hour emission limits of this construction permit were clearly based on the maximum heat input capacity of the boilers which is presumably one of the reasons the heat input capacity was listed in the Allowable Emissions Summary Sheet table.

Any and all terms of permits issued under the Arkansas SIP are federally enforceable. Specifically, the PSD regulations define "federally enforceable" as:

> ***all limitations and conditions which are enforceable by the Administrator***, including those requirements developed pursuant to 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, any permit requirements established pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR part 51, subpart I, including operating permits issued under an EPA-approved program that is incorporated into the State implementation plan and expressly requires adherence to any permit issued under such program.

40 C.F.R. § 52.21(b)(17) (emphasis added).

Permit No. 263-AR-1 was issued under the "Regulations of the Arkansas Plan of Implementation for Air Pollution Control." Permit No. 263-AR-1 at 1 (Ex. 6). The "Regulations of the Arkansas Plan of Implementation for Air Pollution Control and the Arkansas Air Pollution Control Code" have been approved as part of the Arkansas SIP since October 5, 1976 (41 Fed.Reg. 43904); 40 C.F.R. §51.170(c)(4). Revisions were approved on February 23, 1989 (54 Fed.Reg. 07764); 40 C.F.R. §52.170(c)(4), and on May 1, 1989 (54 Fed.Reg. 18494); 40 C.F.R. §52.170(c)(27). These regulations were part of the SIP at the time Permit No. 263-AR-1 was issued for the White Bluff facility in 1991 and, thus, this permit was clearly issued under the SIP.[29]

All conditions of permits issued under a SIP-approved permitting program are federally enforceable. *See* 40 C.F.R. § 52.23; *see also* May 20, 1999 letter from EPA to Robert Hodanbosi, Enclosure A, at pdf 4 (Ex. 82). Accordingly, the 8700 MMBtu/hr heat input capacity of the White Bluff boilers specified in the Permit Summary and in Table 1 ("Allowable Emissions") of Permit 263-AR-1 is a federally enforceable permit condition.[30]

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[29] It appears the version of these regulations last approved into the Arkansas SIP before the 1991 Permit No. 263-AR-1 was issued is posted on EPA's Arkansas SIP regulation website at http://yosemite.epa.gov/r6/Sip0304.nsf/home!OpenView&Start=1&Count=30&Expand=2.4#2.4 (under Arkansas SIP Regulations: SIP effective until 2000.11.15 (November 15, 2000)).

[30] EPA has previously addressed a similar issue in Arkansas. In an October 2006 letter to ADEQ, EPA referred to the coal specification provisions in its 1978 PSD permit for another Entergy plant, the Independence plant, as firm requirements of the permit. EPA stated that "[t]he PSD permit for Independence Station ***contains a condition requiring the use of coal with a heat content of 8700 British thermal unit (Btu)/pound (lb) and a maximum sulfur and ash content of 0.45% and 8%, respectively***." October 4, 2006 Letter from EPA to ADEQ at 2 (emphasis added) (Ex. 9). Like the limits on heat, sulfur and ash content of coal to be combusted in the Independence PSD permit, the limits on heat input capacity in Condition IV of the prior White Bluff Title V Permit (No. 0263-AOP-R6) and in Permit No. 0263-AR-1 are federally enforceable limits.

ADEQ is required to include requirements of construction permits issued under the SIP in Title V permits as applicable requirements. APCEC Reg. 26, Chapter 2, definition of "applicable requirement" at ¶¶(A) and (B); *see also* May 20, 1999 Letter from EPA to Robert Hodanbosi, Enclosure A, at pdf 4 ("All . . . terms and conditions in SIP-approved permits are already federally enforceable (see 40 CFR § 52.23). [footnote omitted] The enactment of title V did not change this. To the contrary, all such terms and conditions are also federally enforceable "applicable requirements" that must be incorporated into the Federal side of a title V permit [see CAA § 504(a); 40 CFR § 70.2)]") (Ex. 82). Accordingly, ADEQ has incorporated the 8700 MMBtu/hr heat input capacity limit, by specifying the 8700 MMBtu/hr heat input capacity of the White Bluff units in all of the Title V permits issued for White Bluff. Now ADEQ claims this limit is not and was never intended to be an enforceable requirement. However, if for no other reason, this limit is federally enforceable because it was a limitation in a construction permit issued under the Arkansas SIP.

Although ADEQ did not make this claim, Entergy claimed in its March 22, 2012 letter to ADEQ responding to comments on the draft White Bluff Title V permit that Permit No. 0263-AR-1 was superseded by Title V operating permit 0263-AOP-R0. However, as addressed previously, EPA has clarified that this sort of supersession is prohibited. Specifically, EPA has concluded that:

> It is the Agency's view that title V permits may not supersede, void, replace, or otherwise eliminate the independent enforceability of terms and conditions in SIP-approved permits. To assure compliance with "applicable requirements" such as SIP-approved permit terms and conditions, title V permits must record those requirements, but may not eliminate their independent existence and enforceability under title I of the Clean Air Act (*i.e.*, may not supersede them). Title V permits may state that they "subsume" or "incorporate" SIP-approved

> permit terms and conditions as EPA interprets such statements to mean that the title V permit includes all SIP-approved permit terms, but does not supersede, void, replace, or otherwise eliminate their independent legal existence and enforceability. Regardless of terminology, to the extent that title V permits are used to accomplish the legal result of supersession, EPA believes that such use is improper.

May 20, 1999 Letter from EPA to Robert Hodanbosi, Enclosure A, at pdf 4 (Ex. 82).

Further, EPA states "if a State does not want a SIP provision or SIP-approved permit condition to be listed on the Federal side of a Title V permit, it must take appropriate steps in accordance with title I substantive and procedural requirements to delete those conditions from its SIP or SIP-approved permit. If there is not such an approved deletion and a SIP provision or condition in a SIP-approved permit is not carried over to the title V permit, then that permit would be subject to an objection by EPA. *Id.* There is no record that ADEQ has gone through any formal proceedings to delete the heat input condition from the SIP Permit No. 0263-AR-1.

For all of the above reasons, Permit No. 0263-AR-1 includes a federally enforceable limit on maximum hourly heat input of the White Bluff boilers and, thus, the 8700 MMBtu/hr limit of the White Bluff Title V permit must be considered a federally enforceable condition applicable to White Bluff Units 1 and 2.

c. *ADEQ's Claims that the Heat Input Capacity Limit Is Not Federally Enforceable Due to Lack of Appropriate Monitoring Requirements is Without Merit.*

ADEQ and Entergy contend that 8700 MMBtu/hr heat input limit in Permit Permit No. 263-AR-1 (Ex. 6) cannot be enforceable because it lacks any specified mechanism in the permit for assessing compliance. However, as discussed *supra*, all the necessary requirements to determine compliance with the heat input limitation set forth in Permit No. 263-

AR-1 are set forth in both the prior White Bluff Title V Permit (No. 0263-AOP-R6) at Conditions IV.20. at pdf 28, IV.21 at pdf 28 and IV.23 at pdf 28, and in the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) at Conditions IV.20. at pdf 26, IV.21 at pdf 27 and IV.23 at pdf 27. The standard itself establishes an hourly averaging time and, consistent with that standard, all the specific provisions cited above require Entergy to measure and record hourly heat input to each White Bluff boiler by calculating heat input rate from monitors for flow rate and diluent, which must be monitored continuously pursuant to 40 C.F.R. § 75.10(a)(3), and to submit the hourly heat input data to EPA. Thus, both the prior White Bluff Title V permit and the recently issued final Title V renewal permit include all the requirements necessary to ensure that the heat input capacity limits in Permit No. 263-AR-1 are practically enforceable.

The lack of monitoring requirements in Permit 263-AR-1 (issued under the SIP-approved regulations) for the 8700 MMBtu/hr heat input capacity limits does not render the limits as not federally enforceable. As previously stated, all terms and conditions issued under SIP-approved permitting programs and federally enforceable pursuant to 40 C.F.R. § 52.23. While the lack of specific testing and monitoring requirements being clearly identified in a permit can make the limits difficult to enforce in practice, it unfortunately was not uncommon for permits and/or SIP provisions to lack specific monitoring requirements that identified how to measure compliance with a limit. EPA recognized this when it promulgated the Part 70 operating permit regulations implementing Title V of the Clean Air Act, by requiring Title V operating permits to include relevant monitoring requirements necessary to ensure compliance with emission limits when the underlying requirement fails to specify to specify such monitoring requirements. 57 Fed. Reg. 32250 (July 21, 1992); 40 C.F.R. § 70.6(a)(3)(i)(B). As such, the first Title V operating permit

issued for the White Bluff facility in 1998 included requirements to monitor heat input capacity for every hour in accordance with the provisions of 40 C.F.R. Part 75, Appendix F, and all subsequent Title V permits for White Bluff have included monitoring and testing provisions for heat input to be measured on an hourly basis. Permit No. 0263-AOP-R0, Condition 22, at 16 (Ex. 44); *see also, e.g.*, Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6), Condition IV.23, at 24 (Ex. 2), and Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition IV.23., at 27 (Ex. 72).

Moreover, before the first Title V permit was issued, monitoring and test methods for measuring heat input on an hourly basis were specified in 40 C.F.R. Part 60, Subpart D and Appendix A. Permit 263-A R-1 specified that the White Bluff units were subject to 40 C.F.R. Part 60, Subpart D, and that the White Bluff units were required "to continue to conform to the requirements" of 40 C.F.R. Part 60, Subpart D. Permit 263-AR-1, Specific Condition 2, at 5 (Ex. 6). Thus, Permit 263-AR-1 did inherently include test methods for hourly heat input by incorporating and requiring compliance with all provisions of 40 C.F.R. Part 60, Subpart D.

For all of the above reasons, ADEQ's claim that the the 8700 MMBtu/hr heat input capacity limit of the White Bluff permits is not enforceable due to the lack of compliance mechanisms being specified in the permit is wholly without merit. Significantly, both the Pre-Existing White Bluff Title V Permit and the Final White Bluff Title V Renewal Permit include requirements to monitoring heat input on an hourly basis and reference the applicable testing procedures. *See, e.g.*, Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6), Conditions IV.20, IV.21 and IV.23 (Ex. 2); Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Conditions IV.20, IV.21 and IV.23 (Ex. 72).

d. *The Maximum Hourly Heat Input and Hourly Coal Burning Capacity Limits Applicable to the White Bluff Units Set Forth in Relevant Permit Applications Are Inherent Components of the White Bluff Title V Permit Which Are Critical to the Permit's Overall Integrity and Were Incorporated by Reference Into Prior Versions of the White Bluff Title V Permit, Unquestionably Making Them Applicable Requirements.*

Even if the 8700 MMBtu/hr maximum heat input limit,[31] like the 525 tons per hour coal throughput limit, was not expressly set forth in any prior SIP or Title V permits and was only set forth in Title V permit applications, each of those limitations would remain "applicable requirements." 40 C.F.R. § 70.2; APCEC Reg. 26, Chapter 2 (definition of "applicable requirement"); *see also* 40 C.F.R. § 70.6(a)(1). Beyond the sound principle that sources should construct and operate sources consistent with substantive permit application specifications, *see generally* 40 C.F.R. § 52.21(r), the maximum heat input and hourly coal throughput limits should be treated as applicable requirements because they have both been inherent components of prior versions of the White Bluff Title V permit which have served to maintain the overall integrity of critical permit limits and because, as such, they have both been repeatedly adopted into earlier iterations of the White Bluff's Title V permit.

In EAI's first Title V application in 1996 for White Bluff Title V Permit (No. 0263- AOP -R1) (Ex. 5) and its subsequent permit modification application submitted in 2006 for the Pre-

[31] This heat input limit has been repeatedly set forth in White Bluff permits, including Title V permits, since 1991. *See* Permit No. 0263-AR-1 at pdf 5, pdf 7 (Ex. 6); Pre-Existing White Bluff Title V Permit (No. 0263- AOP- R6) at pdf 20 (Ex. 30).

Existing White Bluff Title V Permit (No. 0263-AOP-R6) (Ex. 30), EAI certified that the heat input capacity and maximum operation rate for its two boilers was 8700 MMBtu/hr and the maximum coal throughput per hour was 525 tons of coal per hour for each boiler. April 22, 1996 White Bluff Permit Application, Emission Rate Tables for SN-01 and SN-02, at pdf 7, pdf 9 (Ex. 4); February 2006 Emission Rate Tables for SN-01 and SN-02, as corrected in a March 2, 2006 e-mail from George Johnson, EAI, to Ann Sudmeyer, ADEQ at 2-3 (Ex. 3). In the corresponding Title V permits, ADEQ expressly adopted these requirements as permit conditions using substantially identical language: "[t]his permit authorizes the above referenced permittee to install, operate, and maintain the equipment and emission units described in the permit application and on the following pages." *See* Permit No. 263-AOP-R1 at pdf 1 (Ex. 5); Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6) at pdf 5 (Ex. 30). Now, in the context of the final issued White Bluff Title V permit, ADEQ has elected to treat those limitations as though they were meaningless descriptions which can be adjusted at will.[32]

Contrary to the positions taken by ADEQ and EAI, the White Bluff maximum heat input and hourly coal combustion limitations are not inconsequential descriptions that can be relaxed or ignored. Limits on heat rate and production rate are critically important in the permitting context because an increase in the heat input or coal combustion results in an increase in actual emissions. The U.S. Department of Justice ("DOJ") highlighted this point in the context of a

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[32] ADEQ's position on this issue has been shifting. In May of this year, ADEQ recognized that the 8700 MMBtu/hr heat input limit was an essential component of the overall structure of the Title V permit which "need[ed] to be included in the permit . . . ." May 2012 ADEQ Response to Comments at 3 (Ex. 74). For this reason, ADEQ endeavored to create a new heat input limit with a 24-hour averaging period for "particulate emission rates and particulate National Ambient Air Quality Standard (hereinafter "NAAQS")" instead of relying on the existing 1-hour averaging period. Now ADEQ has abandoned that position.

summary judgment brief addressing alleged PSD violations:

> A boiler's maximum heat input rate is thus a measure of its size or capacity. Clearly, then, a coal-fired boiler's heat input rate is directly related to the amount of pollution it can emit. Congress' understanding of this fact in the context of the Clean Air Act is evidenced by the fact that heat input is used to determine which sources are potentially subject to the statutory PSD program. See 42 U.S.C. § 7479(1) (defining "fossil-fuel fired steam electric plants of more than two hundred and fifty million British thermal units per hour heat input" as a type of stationary source). As an example of the direct relationship between heat input capacity an the amount of pollution, [a boiler] permitted to burn coal containing an specific amount of sulfur dioxide (SO2), as measured in pounds of SO2 per mmBtu. For any given coal SO2 content (*i.e.*, pounds of SO2 per mmBtu), there is a direct and linear relationship between heat input and SO2 emissions. By increasing its heat input capacity, [the boiler] increases its capacity to generate steam and SO2 ...
>
> ***The rated heat input capacity of a boiler is not a meaningless number. Rather, it is directly related to the capacity of the boiler to emit pollution. In the absence of a boiler heat input capacity in the description, [the boiler] could be a unit of any size, which would translate into widely ranging impacts on the environment. Common sense thus dictates that a permit concerned with emissions must limit the heat input of the boiler. Otherwise, the regulated unit is not really limited in its capacity to pollute. . . . The greater the capacity of the boiler, the more tons of SO2 that will be emitted into the atmosphere. Thus, heat input capacity plays a very real role in effectively limiting a source's capacity to emit pollution***. . . .
>
> By increasing the heat input over the levels identified in its applications, [the company] has fundamentally changed the assumptions upon which approval to construct the unit was based. If air quality modeling were to be done using a higher heat input capacity and the same coal sulfur content that was identified in [the company's] permit application... the unit would have been modeled at a higher emissions rate because increasing the heat input rate is directly proportional to the amount of emissions from a unit.

United State's Memorandum in Support of its Sixth Motion for Summary Judgment, *United States v. East Kentucky Power Cooperative, Inc.*, Case No. 04-34 KSF (E.D. Ky), pp. 16-17, 20-21, 36-37(emphasis added) (Ex. 83).

As stated above, as a condition of operation, both Permit No. 263-AOP-R1 at pdf 1 (Ex. 5) and the Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6) at pdf 5 (Ex. 30)

imposed the obligation on EAI to operate the equipment as described in their respective permit applications. And those corresponding permit applications included the 8700 MMBtu/hr maximum heat input limit and the 525 tons per hour coal throughput conditions. Consequently, those conditions became enforceable permit terms and conditions which are "applicable requirements." This is only reasonable, as a change in heat input (or in coal combusted) can have a significant impact on actual emissions.

A similar situation was addressed by EPA in *In the Matter of Alliant Energy - WPL Edgewater Generating Station*, Permit No. 460033090-P20, Petition Number V -2009-02, Order at 1-6 (Adm'r August 17, 2010) (Ex. 84). There, the permittee applied for a Title V renewal permit for its Edgewater plant which was issued by the Wisconsin Department of Natural Resources ("WDNR") in August of 2009. Much earlier, in 1976, the permittee had submitted a PSD application which included several operational conditions, including maximum hourly heat input limits and maximum and average hourly coal usage limits. *Id.* at 3-4. In 1977, a PSD permit based on that 1976 application was issued.[33] *Id.* at 3, 5. That permit did not specifically include the heat input limits, coal usage limits and other conditions set out in the permit application. However, it did include the following statement:

> Approval to construct a 400 MW electrical generating unit is hereby granted to the [permittee] subject to the condition expressed herein and consistent with the materials and data included in the application filed by the Company. Any departure from the conditions of this approval or the terms expressed in [the permittee's] application must receive the prior written authorization of U.S. EPA.

Id. at 3.[34]

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[33] This PSD permit was revised in 1984. *Id.* at 3.

[34] Sierra Club also relied on a 1979 construction permit. *Id.*

Immediately prior to the issuance of the 2009 Edgewater Title V permit, Sierra Club filed a petition with EPA contending, *inter alia*, that the Title V permit was unlawful because it failed to include all applicable requirements. Specifically, Sierra Club asserted that the permit failed include the limits on "heat input, fuel usage" and other parameters which were included in the 1976 PSD application submitted in 1976. *Id.* at 3. Sierra Club argued that the Edgewater PSD permit required the permittee to construct and operate the Edgewater plant "consistent with and according to the plans and specifications submitted with the Edgewater PSD permit application" and an associated air quality modeling analysis which was performed. *Id.* at 4. According to Sierra Club, these conditions, which were set forth only in the PSD permit application and which included maximum hourly heat input limits and maximum and average hourly coal usage limits, were "applicable requirements" of the Title V permit. *Id.* at 4. Because the Title V permit issued for Edgewater failed to include these limits, Sierra Club maintained that the Title V permit was unlawful.

In response to these arguments, EPA reasoned as follows:

> ***The 1977 PSD permit imposes enforceable lb/MMBtu emission limitations and states that approval to construct "is hereby granted to the Wisconsin Power and Light Company subject to the conditions expressed herein and consistent with the materials and data included in the application filed by the Company."*** PSD Permit EPA-5-77-A-3 § 8. The permit states further that "[t]he air quality analysis relies heavily on the combination of stack parameters, control devices, and emission limitations and any change in those factors could change the results of the air quality analysis. Therefore, design changes in Unit 5 must receive the prior written authorization of U.S. EPA." *Id* § 7(C).3. The permit was issued based on the information presented by the applicant at the time of permit issuance. ***The heat input rate along with other factors appear to have been relied upon when performing the air quality analysis and assessing the project's impacts to air quality. Therefore, it appears that the integrity of the permit's lb/MMBtu emission limitations may depend upon the heat input and other factors used to assess air quality at the time of permit issuance.***

> Based upon its response to comments, WDNR apparently agrees that the conditions cited by Petitioner are part of a construction permit and that "conditions in a construction permit do not expire and continue to be enforceable unless revised or eliminated through a construction permitting review process." However, WDNR's reference to permit "conditions" is ambiguous as to whether it includes information such as heat input and coal usage rates contained in the permit application rather than the permit. In any event, WDNR failed to make any corresponding changes to the title V permit or to explain why it did not do so.

Id. at 5. (emphasis added).

After concluding that the integrity of the Edgewater Title V permit's pounds per hour emission limits may depend on heat input and other factors (which presumably would also have included coal throughput limits), EPA required WDNR to respond to a series of substantive questions, including, notably, "how the lb/MMBut limits in the title V permit in the absence of these parameters are sufficient to assure compliance with those permits." *Id.* at 6.

Generally, the EPA's response to the *Edgewater* petition stands for the common sense proposition that permittees are required to construct and operate sources in strict accordance with the permit applications which served as the basis for their authorization to proceed. More significant for the purposes of this petition, *Edgewater* clarifies that substantive conditions governing parameters such as heat input and coal throughput are considered applicable requirements, even when they are only set forth in a permit application, where those conditions serve as the basis for assessing compliance with emission limits explicitly set forth in permits and where those permit application conditions are inherently necessary permit components which must exist to maintain the integrity of permit limits.

The same basic factual scenario addressed in *Edgewater* is presented here. The heat input and hourly coal throughput limits at issue were central components of several permit

applications, including the application for White Bluff's first Title V permit, Permit No. 263-AOP-R1 (Ex. 5); April 22, 1996 White Bluff Permit Application, Emission Rate Tables for SN-01 and SN-02, at pdf 7, pdf 9 (Ex. 4), and the application for its 2006 Title V modification permit. Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6) (Ex. 30); February 2006 Emission Rate Tables for SN-01 and SN-02, as corrected in a March 2, 2006 e-mail from George Johnson, EAI, to Ann Sudmeyer, ADEQ at 2-3 (Ex. 3). The relevant permits were issued under the condition that the permittee operate the equipment as "described" in the permit application. And the subject limits on heat input and hourly coal throughput undergird several important pounds per hour limits in the Final White Title V Renewal Permit, including SO2, NOx, CO, lead, PM, PM10 and virtually all of the lb/hour hazardous air pollutant limits. Final White Bluff Title V Permit (No. 0263-AOP-R7), Conditions IV.1 and IV.2 at pdf 20-22 (Ex. 72); *see also* White Bluff Title V Permit (No. 0263-AOP-R6), Conditions IV.1 and IV.2, at 16-19 (Ex. 2).

For example, Condition IV.2 of the Final White Bluff Renewal Permit has a limit on hydrogen fluoride emissions (HF) of 78.8 pounds/hour and 345.0 tons per year. According to current and past Statements of Basis for the White Bluff Title V Permits, compliance with this limit is based on coal throughput and AP-42 emission factors. *See, e.g.*, Statement of Basis for Permit No. 0263-AOP-R4 at 9-10 (Ex. 39); *see also* August 2012 ADEQ Statement of Basis for Permit 0263-AOP-R7 at 6-7 (Ex. 77). The AP-42 emission factor for HF is 0.15 lb/ton of coal burned. AP-42, Table 1.1-15. The emission limits in the White Bluff permit are tied to the pre-existing ton per hour maximum coal throughput identified in prior White Bluff permit applications. Specifically, 0.15 lb HF/ton of coal x 525 tons of coal per hour = 78.8 lb/hr (the HF limit in Condition IV.2 of the White Bluff permit). Permit No. 0263-AOP-R6, Condition IV.1

and IV.2, at 17-18 (Ex. 2); Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Conditions IV.1 and IV.2., at 20-21 (Ex. 72). Multiplying the pound per hour limit by 8760 hours per year equals an annual HF limit of 344.9 tons per year, which it appears ADEQ rounded up to 345 tons per year in Condition IV.2. *Id.*

With the increased hourly coal burning capacity allowed in the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7), compliance with both the lb/hr and ton per year HF limits is compromised. ADEQ claims that, by retaining the annual plantwide limit on coal throughput of 9.2 million ton coal per year, the annual coal throughput will not ensure that emissions from either White Bluff unit will not increase. August 2012 ADEQ Final Response to Comments at 6 (Ex. 76). However, the 9.2 million ton coal throughput limit that applies on a facility-wide basis will not in any way ensure compliance with these limits. This is best explained through an example.

Suppose that Unit 1 operates at 540 tons of coal per hour throughput for 8700 hours in one year. The unit's hourly emissions will exceed the pound per hour HF limit in the permit 8,700 times (*i.e.*, 540 tons per hour x 0.15 lb/ton = 81 pounds per hour). Further, the unit will exceed the ton per year HF limit (*i.e.*, 540 tons per hour x 0.15 lb/ton x 8700 hrs = 704,700 pounds per year or 352.4 tons per year). Suppose that Unit 2 operates at 540 tons per hour for 8,335 hours per year. That unit will violate the pound per hour HF limit 8,335 times (*i.e.*, 540 tons per hour x 0.15 lb/ton = 81 lb/hr), although Unit 2 will not violate the 345 ton per year limit (*i.e.*, 540 tons per hour x 0.15 lb/ton x 8335 hours = 337.6 tons per year HF). However, although the Units will violate the HF limits of the permit, the facility will not exceed the 9.2 million coal throughput facility-wide condition (tons of coal burned = 540 tons per hour x 8700 hrs + 540

tons per hour x 8335 hours = 9,198,900 tons of coal burned facility-wide). This example illustrates two points: (1) that the 9.2 million ton coal throughput that applies on a facility-wide basis does not ensure there will be no emission increases as a result of the increase in coal burning capacity of the units, and (2) that the ton per hour coal throughput of the permit application must be considered an enforceable part of the permit to ensure compliance with the pound per hour emission limits in Condition IV.2.[35]

Without the heat input and related hourly coal throughput limits, there is no mechanism for assuring continuous compliance with these important limits and, therefore, as EPA strongly implied was its position in the *Edgewater* petition response, these operational limits set forth in the permit applications for the original White Bluff Title V permit and the 2006 permit modification must be considered "applicable requirements." *See also* March 27, 2008 Letter from EPA Region 5's C. Newton, Acting Director, Air and Radiation Division, to K. Kessler, Director, Bureau of Air Management, WDNR, Regarding the Weston Generating Station's Title V Permit Modification and Petition Response at 2-3 (indicating EPA's suspicion that a

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[35] Even if the ton per hour coal throughput was not included as part of the permit or otherwise considered federally enforceable, compliance with the lb/hr limits could be determined based on the maximum hourly heat input. Based on information provided by Entergy on the heating value of the coal at White Bluff, the average heat value is 8,286 Btu/lb, 2009 Title V Permit Renewal Application at 3.1.1.3, 3-2 pdf 23; Appendix A - Emission Unit Forms, Emission Rate Table at pdf 55, 59; Appendix C - Detailed Emissions Calculations, Facility Data at pdf 94; Emission Rate Table 180-81 (Ex. 1), and this coal heat value has remained consistent throughout the Title V applications submitted by EAI for White Bluff. A boiler with a capacity of 8700 MMBtu/hr heat input that burns 8286 Btu/lb coal could burn 525 tons of coal per hour:

$$\frac{\text{8700 MMBtu/hr}}{\text{8286 Btu/lb x 2000 lb/ton x 1 MMBtu/10\^6 Btu}} = \text{525 tons of coal per hour.}$$

This exercise reveals that the 8700 MMBtu/hr heat input limit and the 525 tons per hour limit are, and have always been, interrelated and reflective of each other.

maximum heat input condition in a Title V permit application for a 1977 Title V permit, which had been issued with a condition indicating that the permit was issued "consistent with materials and data included in the [associated] application," was likely an "applicable requirement" which would ultimately have to be included in a 2006 proposed Title V permit unless those heat input limits had been specifically modified in the past) (Ex. 85); EPA Memorandum Regarding PSD Sunflower Electric, Holcomb, KS (from files of U.S. EPA Region VII Air Permitting and Compliance Branch) at 1 (heat input, among other things, which was proposed in an application for a PSD permit which in turn was "issued for the project 'as proposed' by the company" was an enforceable limitation.") (Ex. 86); January 24, 2003 Notice of Violation Issued to East Kentucky Power Cooperative at 3-5 (repeated attempts to relax heat input limit and to place it in ambiguous "descriptive" section of Title V permit was basis for assertion of EPA's claims for PSD violations and permit exceedences) (Ex. 87); Letter from Beverly H. Banister, Directors Air. Pesticides and Toxics Management Division, U.S. EPA Region IV, to John S. Lyons, Kentucky Department for Environmental Protection (February 18, 2006) Objecting to TVA's Title V Permit for Paradise Plant at 1-2 (objection based on failure to include maximum heat input limits from non-Title V state operating permits which were incorporated into state SIP) (Ex. 88).

2. ADEQ Cannot Relax the Federally Enforceable Limits on Heat Input Capacity or On Hourly Coal Throughput Through the Issuance of the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) Without Evaluating this Change in the Method of Operation for Applicability to PSD Permitting Requirements.

For all of the reasons set forth above, the increase in heat input capacity and coal throughput that ADEQ has allowed in issuing the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) cannot be authorized without an evaluation of the changes in the method of

operation at the White Bluff source for PSD applicability. Such an evaluation would likely result in a determination that this action allowing for a 2.9% increase in heat input capacity at each White Bluff boiler would trigger the application of the PSD permitting requirements as a major modification for at least SO2, NOx, PM2.5, and probably also greenhouse gases.

In addition to claiming that the hourly heat input and coal throughput limits of the permit are not enforceable limitations, ADEQ has indicated that this permit action will not trigger PSD review because ADEQ has not allowed for any increase in hourly or ton per year emission limits of the permit. August 2012 ADEQ Final Response to Comments at 6 (Ex. 76). Whether or not allowable emissions will increase is not relevant to determining PSD applicability. As will be discussed later in this petition, PSD applicability is based on changes in actual emissions.

C. There Likely Have Been Physical Changes and/or Changes Are Forthcoming at White Bluff Units 1 and 2 That Will Enable the White Bluff Units to Accommodate an Increase in Heat Input Capacity and Coal Throughput at the Boilers.

Although the change in the method of operation at the White Bluff units discussed at length above is enough to trigger the applicability of PSD permitting requirements as a major modification (by increasing production rates above federally enforceable limits), Entergy also appears to have made a number of physical changes to allow for and accommodate the increase in heat rate and hourly coal throughput that provide a separate basis for PSD applicability and more changes are likely planned in the future.

For example, in the context of a prior PSD permit applications, Entergy admitted that the increase in heat input of the boilers was also related to planned physical changes at the White Bluff plant. Specifically, Entergy told ADEQ that it was requesting the same heat input capacity

increase in conjunction with turbine upgrades and the installation of planned pollution controls at each unit. On February 4, 2009,[36] EAI submitted a PSD permit application to ADEQ for the installation of SO2 and NOx pollution controls to meet best available retrofit technology ("BART") requirements. In that PSD permit application, EAI stated:

> Operation of the new air pollution control (APC) systems will result in an estimated 6% increase in parasitic electricity load due to additional pressure drop and the operation of new mechanical equipment. Steam turbine efficiency upgrades are proposed as part of the project which will recover about half of these station losses. ***In order to maintain current rated net station generating capacity, an increase in boiler firing rate of about 2.9% (and resulting emission increases) is being permitted as part of this PSD application***. As a result of all of the proposed project changes, collateral emission increases of PM, VOC, sulfuric acid mist (H2SO4), lead (Pb), and CO are expected to exceed Prevention of Significant Deterioration (PSD) permitting thresholds.

January 2009 Application for Permit to Construct Entergy White Bluff Units 1 & 2 Air Pollution Control Project at 1-1, pdf 8 (emphasis added) (Ex. 64); January 2009 Application for Permit to Construct Entergy White Bluff Units 1 & 2 Air Pollution Control Project at 1-1 (Ex. 10).

EAI further provided:

> As part of the Project being proposed, Entergy Arkansas is proposing to perform simultaneous steam turbine efficiency improvements on Units 1 and 2 in order to recover output that would otherwise be lost from the air pollution control project. ***In addition to these steam turbine upgrades, approximately 2.9% more coal (in MMBtu/hr) will have to be fired in Units 1 and 2 to maintain their present net electrical output***. . . .
>
> The existing coal handling systems are shown in a process flow diagram in Appendix B for reference. ***No physical changes are being proposed to these systems although annual coal throughput is expected to increase by 3% as a result of the Project***.

Id. at 2-9, pdf 20 (emphasis added).

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[36] The cover letter from EAI lists the date as February 4, 2008 but that appears to have been a typographical error.

In the permit application forms for the requested PSD permit, Entergy listed the heat input capacity of the boilers to be 8950 MMBtu/hr and listed the proposed maximum production/operation rate as 540 tons per hour of coal. *Id.*, Section 8.0 ADEQ Application Forms, pages for SN-01 (White Bluff Unit 1) and SN-02 (White Bluff Unit 2), at pdf 90-91 (Ex. 64); January 2009 Application for Permit to Construct Entergy White Bluff Units 1 & 2 Air Pollution Control Project at 92-93 (Ex. 10). These and other related statements were included in revisions to Entergy's permit application that were submitted to ADEQ in July 2009 and August 2009. And, as stated above, these same increased levels of heat input and hourly coal throughput were also included in Entergy's October 20, 2009 Title V Permit Renewal Application. October 20, 2009 White Bluff Title V Renewal Application, Appendix A, Emission Unit Forms for SN-01 and SN-02 (White Bluff Units 1 and 2) at pdf 55, pdf 59 (Ex. 1). These levels of coal throughput reflect an increase of about 3% from 8700 MMBtu/hr and 525 tons per hour, *i.e.*, the levels that were identified as maximum capacity in all previous Title V permits and permit applications.

Subsequently, in October 2009, Entergy submitted a revised PSD application to ADEQ that sought to unring the bell by removing all references to any increases in coal feed rate to the boilers as a result of the turbine efficiency project. Entergy's October 8, 2009 letter to ADEQ at 1 (Ex. 65) specifically stated:

> Per our discussion, Entergy is submitting revised pages necessary to more accurately describe the beneficial impact of the White Bluff Turbine Upgrade Project. . . .The current application references "parasitic losses" in MWs that would be incurred as a result of this project and that would necessitate additional fuel use. Based on further discussions with staff and review of engineering studies, this loss will be fully recovered by the planned Turbine Upgrade Project without the utilization of additional fuel. These clarifications do not impact

emissions calculations contained in the application.

Notably, Entergy did not state that the turbine upgrades would not allow or require for an increase in heat input capacity of the boilers. In fact, Entergy continued to request an increase in permitted heat input capacity of the White Bluff boilers. In its October 2009 PSD permit application changes, Entergy addressed this discrepancy by stating "[t]he assumed maximum heat input will be increased from 8700 MMBtu/hr to 8950 MMBtu/hr, ***based on past historical data***." *See* Entergy file entitled "Mark-up of change pages for application.pdf" at 4-1 (emphasis added) (Ex. 66). Entergy's Title V Renewal Application submitted in October 2009 also requested an increase in permitted heat input capacity based on historical data. *See* October 20, 2009 White Bluff Title V Renewal Application at 1 (Ex. 1). Entergy did not identify and provide any meaningful description of the "historical data" it was referring to.

Although Entergy later withdrew the PSD permit application because the company obtained a variance from meeting the BART requirements of Arkansas Regulation No. 19, May 7, 2010 Letter from Entergy's M. Bowles to ADEQ's T. Rheaume Withdrawing Permit Application at 1 (Ex. 70), it appeared from some documentation that the company might have gone ahead with the high pressure turbine upgrades. According to a loan guarantee request for the Arkansas Electric Power Cooperative ("AECC") to the Rural Utilities Service ("RUS"), a partial owner of the White Bluff facility, a high pressure turbine upgrade was planned for 2010 to 2011 at White Bluff Unit 1 and a high pressure turbine upgrade was planned for the same timeframe at White Bluff Unit 2. *See* Arkansas Electric Cooperative Corporation's 2009-2012 Rural Utilities Service (RUS) Generation Construction Work Plan and Request for RUS Approvals, submitted to the Rural Utilities Service August 10, 2009, Part III, Item III, Tables for

White Bluff Unit 1 and for White Bluff Unit 2, at pdf 8, pdf 10 (Ex. 12). Based on reports submitted by Entergy to the Arkansas Public Service Commission, it appeared that the Unit 1 HP turbine upgrade was completed in May of 2009, earlier than indicated in the loan guarantee request to the RUC.[37]

The statements in Entergy's January 2009 PSD permit application regarding the need to burn more coal with the high pressure turbine upgrades were consistent with statements made by utility experts and vendors regarding high pressure turbine upgrades. That is because new high pressure turbines take so much energy off the steam path that the steam needs to be heated to a higher temperature when it goes back to the boiler before going through the intermediate pressure and low pressure turbines.[38] Otherwise, the benefits of increased generation capacity that should occur with the high pressure turbine upgrade will be lost due to decreased electrical generation across the intermediate and low pressure turbines.

Despite the documentation discussed above which suggests that the high pressure turbine upgrade work has already been performed at White Bluff, ADEQ has firmly asserted that despite the fact that EAI included those "upgrades as part of the PSD project [in the prior abandoned permit] . . . they were never conducted" at White Bluff. August 2012 Final ADEQ Response to Comments at 6 (Ex. 76); May 2012 ADEQ Response to Comments at 4 (Ex. 74). Assuming, *arguendo*, that this unsubstantiated contention is true and the turbine upgrade projects are

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[37] Some documentation obtained by Sierra Club suggested that the high pressure turbines for both the White Bluff units had already been upgraded. *See* Entergy-Arkansas' FERC Form 1 Supplement Annual Report, 2009, Supp E-5, at pdf 14 (Ex. 11); *see also* Entergy-Arkansas' FERC Form 1 Supplement Annual Report, 2010, at Supp E-5 (Ex. 71).

[38] Sierra Club provided extensive support for this claim in its November 23, 2011 comment letter to ADEQ at 14-15 and Exs. 13 and 14 to that letter (Ex. 67).

anticipated future projects rather than completed projects, this is of little moment. First, despite when they will be performed, it is clear that the turbine upgrades are planned for the White Bluff units. Second, there are a number other physical changes to White Bluff Units 1 and 2 that have unquestionably taken place. Some or perhaps all of those physical changes were likely performed to accommodate a portion of the increase in maximum heat input and hourly coal throughput sought by EAI.[39]

The fact that EAI has not yet performed these turbine upgrade projects at White Bluff does not mean that EAI does not intend to implement them in the future. To the contrary, it is remarkably clear that EAI plans to increase the "boiler firing rate" at White Bluff boilers (which will result in increased emissions) to recover part of the lost generation associated with the parasitic load of anticipated future BART-related control equipment, *see* January 2009 Application for Permit to Construct Entergy White Bluff Units 1 & 2 Air Pollution Control Project at 1-1, pdf 8 (Ex. 64), and to accommodate that increase through permitting changes – either increases in the permitted heat input and hourly coal throughput limits or actions which result in making those limits unenforceable. This long term plan is reflected in the abandoned Draft White Bluff Title V, PSD and BART Permit (No. 0263-AOP-R7) (assigned the same permit number as present final Title V permit) (Ex. 90) and the associated application materials. January 2009 Application for Permit to Construct Entergy White Bluff Units 1 & 2 Air Pollution Control Project at 1-1, pdf 8, 4-1, pdf 32, pdf 90-91, pdf 102, 104 (Ex. 64); January 2009

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[39] It appears fairly clear that many of the physical changes discussed herein, both the ones that have already been performed and the others, like the turbine upgrades, which are planned for the future, are part of a single long term, multi-phase project intended to allow for the maximum heat input and hourly coal throughput increases sought by EAI in this Title V permit and the prior Title V, PSD and BART permit.

Application for Permit to Construct Entergy White Bluff Units 1 & 2 Air Pollution Control Project at 1-1, pdf 8; 4-1, pdf 32 (Ex. 10). It is also reflected in EAI's latest application for the present Title V renewal permit, which includes a request for a significant increase in the maximum heat input limit from 8700 MMBtu/hr to 8950 MMBtu/hr and an increase in the hourly coal throughput from 525 tons per hour to 540 tons per hour. *See* October 20, 2009 White Bluff Title V Renewal Application, at cover letter and at Appendix A, Emission Unit Forms for SN-01 and SN-02 at pdf 55, pdf 59 (Ex. 1). In both the present Title V permitting action and the prior action involving the abandoned Title V, PSD and BART permit, EAI has been preparing the regulatory ground to accommodate a significant increase the firing rate of the White Bluff boilers by seeking permits which, in one fashion or another, provide for increases in maximum heat input and hourly coal throughput.

The allegedly moribund turbine upgrade projects were only anticipated to "recover about half of the[] station losses" associated with the parasitic load from future BART-related controls. January 2009 Application for Permit to Construct Entergy White Bluff Units 1 & 2 Air Pollution Control Project at 1-1, pdf 8 (Ex. 64). Regardless of whether those projects have been initiated or not, there have been a number of other significant physical changes at the White Bluff boilers which were likely necessary to accommodate the requested increases in maximum heat input and hourly coal throughput and to allow EAI to ultimately, in aggregate, recover the remaining generation losses which EAI desires to recover after BART-related controls are installed.

1. The White Bluff Units 1 and 2 Economizer and Partial Superheater and Reheater Replacements Constituted Physical Changes Which May Have Allowed for an Accommodation of an Increase in Coal Burning and/or Heat Input Capacity of the White Bluff Units.

The economizers for White Bluff Units 1 and 2 have been replaced in recent years and significant portions of the superheaters and reheaters been replaced at each boiler, if they have not been entirely replaced at this juncture. *See* July 31, 2006 Letter from Entergy to ADEQ Regarding Economizer Replacement at White Bluff Unit 1 (Ex. 15); December 7, 2007 Letter from Entergy to ADEQ Regarding Economizer Replacement at White Bluff Unit 2 (Ex. 16); and Response of Entergy-Arkansas, Inc., to Sierra Club's Fourth Set of Data Requests, Response to Request 4-1.e. (Docket No. 09-024-U, White Bluff Declaratory Order), at pdf 2-3 (Ex. 25); *see also* Arkansas Electric Cooperative Corporation's 2009-2012 RUS Generation Construction Work Plan and Request for RUS Approvals, submitted to the Rural Utilities Service August 10, 2009, at Part III, Item III, Tables for White Bluff Unit 1 and for White Bluff Unit 2, at pdf 8, pdf 10 (Ex. 12).

Entergy's replacement of the economizers could have increased the capacity of the boilers. Based on our review of Entergy's annual reports to the Arkansas Public Service Commission, the White Bluff units were having issues with ash pluggage in the economizers which was causing hourly load restrictions. *See* FERC Form 1 Supplement, Annual Report of the Entergy-Arkansas, Inc. for 2003 to 2008 (Exs.18A-18F). If Entergy replaced those economizers with a different design, *e.g.*, from a staggered fin tube design to an in-line tube design, as was done at the Independence economizers, EAI could have essentially eliminated a bottleneck at each boiler and increased hourly heat input capacity. The same basic problems could have likewise been eliminated by the partial and ongoing superheater and reheater replacements.

2. The Replacement of the Circulating Water Flow Pumps for White Bluff

Units 1 and 2 and Associated Increase in the Capacity of those Pumps May Have Allowed Which May Have Allowed for an Accommodation of an Increase in Coal Burning and/or Heat Input Capacity of the White Bluff Units.

In 2006, in response to a series of requests, permit applications, PSD applicability review requests and permit revisions submitted by Entergy and discussed in much more detail *infra*,[40] ADEQ issued the White Bluff Title V Renewal Permit (No. 0263-AOP-R4) (Ex. 36). Among other things, this permit allowed Entergy to increase in the permitted circulating water flow rate of the White Bluff Unit 1 and 2 cooling towers from 20,700 kgal/hr per tower to 22,125 kgal/hr per tower. *Compare* Permit 0263-AOP-R3, Condition IV.80, at pdf 43 (Ex. 29) to Permit 0263-AOP-R4, Condition IV.82, at pdf 42 (Ex. 36). In the midst of the process of obtaining this permit relaxation concerning flow rates, Entergy replaced (or otherwise substantially modified) the circulating water pumps for the White Bluff Units 1 and 2 cooling towers to allow for increase rates, which unquestionably constituted a physical change. *See* generally July 5, 2005 letter from Entergy to ADEQ at 1 (Ex. 47).

The reason for this physical change is almost certainly interwined with coal switch which was contemporaneously being permitted. *See* detailed discussion *infra*. Increasing the flows by replacing the pumps would likely have allowed the White Bluff units to accommodate increased steam generating capacities from the White Bluff boilers which could have been expected from the coal switch, which would likely have required more cooling tower flow to dissipate the

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[40] *See* Permit 0263-AOP-R2, Condition IV.58, at 29 (Ex. 55); Permit 0263-AOP-R3, Condition IV.80, at 43 (Ex. 29); March 23, 2005 Submittal from Entergy to ADEQ regarding the increased flow rate for the White Bluff cooling towers (Ex. 45); March 14, 2005 letter from Entergy to ADEQ at 1 (Ex. 46); July 5, 2005 letter from Entergy to ADEQ (Ex. 47).

increased heat.[41] Accordingly, it may be the case that the increase in permitted water flow capacity of the White Bluff Units 1 and 2 cooling towers and, more significantly, the physical changes performed to achieve that result, were a necessary predicate step not only to accommodating the fuel switch but also more generally to allowing White Bluff Units 1 and 2 to accommodate the increase in maximum heat input and hourly coal throughput that has ultimately been afforded, albeit unlawfully, by the Final Title V renewal permit.

3. Other Miscellaneous Work on White Bluff Units 1 and 2 May Have Constituted Physical Changes Resulting in an Increase in Coal Burning and/or Heat Input Capacity of the White Bluff Units and Emissions.

Entergy's January 2009 PSD permit application also stated that Entergy would be conducting "simultaneous maintenance activities" with the turbine upgrades, including "tubing repairs, refractory repairs, maintenance, [and] repairs to ancillary systems (such as fans, pumps, piping, etc.) . . . ." *See* January 2009 Application for Permit to Construct Entergy White Bluff Units 1 & 2 Air Pollution Control Project, Section 2.2.1.6, at 2-9, pdf 20 (Ex. 64); January 2009 Application for Permit to Construct Entergy White Bluff Units 1 & 2 Air Pollution Control Project, Section 2.2.1.6, at 2-9 (Ex. 10). It is possible that some of these activities were designed to increase the steam flow of the boiler (which would account for their projected increase in heat input capacity of the units) to take full advantage of the turbine upgrade project.

In summary, while the requested increase in heat input capacity and coal throughput in excess of federally enforceable limits on heat input capacity of the White Bluff boilers is alone

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[41] Assuming that Entergy burned the same amount of tons per coal per hour but the coal burned over that time had a higher heat value, the heat input to the boilers would increase. And if the heat input to the boilers increased, that would increase the steam production which, in turn, would require an increase in cooling tower flow capacity.

sufficient to require a PSD applicability review as a major modification, there also were likely physical changes made to the White Bluff facility to accommodate the increase in heat input capacity that would likewise warrant review for PSD applicability. While Sierra Club may not have sufficient specific details about these various projects to conclusively determine whether these projects could have resulted in an increase in coal burning capacity of the boilers, this information is being provided to EPA so it is aware that there have been several physical changes to the White Bluff boilers over the past five years or so and more physical changes are planned in the near future that may be related to EAI's requested increase in heat input capacity.

D. The Increase in Coal Burning Capacity Above the Federally Enforceable Limits Should Have Been Projected to Result in a Significant Emission Increase and a Significant Net Emissions Increase of SO2, NOx, PM2.5 and Likely Greenhouse Gases at Both White Bluff Units 1 and 2.

Regardless of whether physical changes at the White Bluff units are associated with Entergy's requested increase in heat input capacity, the increase in heat input capacity and coal throughput rate authorized in Permit No. 0263-AOP-R7 is a change in the method of operation that should have been evaluated for PSD applicability. As discussed above, the 8700 MMBtu/hr heat input capacity limits of White Bluff permits (Permit Nos. 0263-AOP-R6 and 0263-AR-1) are federally enforceable limits applicable to the White Bluff boilers' production rate. An increase in the allowable amounts of coal to be burned and allowable heat input to the boilers, something that is directly related to how much pollution is emitted from a facility, is a change in the method of operation that must be reviewed for PSD applicability. Therefore, Entergy's requested increase in heat input capacity for its boilers from 8700 MMBtu/hr to 8950

MMBtu/hr,[42] which was effectively granted in the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition IV.26 at pdf 28 (ash content calculation relies on new value of 8950 MMBtu/hr, essentially making this the new maximum heat input limitation), must be reviewed for PSD applicability as a change in the method of operation at the White Bluff facility. Additionally, there could have been physical changes at the White Bluff facility that allowed for the requested increase in heat input capacity of the boilers.

The determination of whether a "project" is a "major modification" is based on a determination of whether it causes two types of emissions increases, (1) a significant emissions increase and (2) a significant net emissions increase. 40 C.F.R. § 52.21(a)(2)(iv)(a). The determination of whether a significant emissions increase will occur as a result of the requested 2.9% increase in heat input capacity and the coal throughout increase at the White Bluff units is to either be based on a comparison of baseline actual emissions to projected actual emissions or actual emissions to the future potential to emit after the project. 40 C.F.R. §§ 52.21(a)(2)(iv) (a), (b)(41), (b)(4), and (b)(48). Thus, even if the Final White Bluff Title V Renewal Permit does not allow for any increases in allowable emission rates, that does not mean no significant emission increase or significant net emissions increase will occur at White Bluff as a result of the requested 2.9% increase in the permitted heat input of both White Bluff boilers.

The PSD regulations define a "significant emissions increase" as an increase in emissions that is considered to be significant - *i.e.*, exceeds a particular emission threshold. 40 C.F.R. § 52.21(b)(40). For SO2 and NOx, those significant emission thresholds are 40 tons per year each. 40 C.F.R. § 52.21(b)(23)(i). In addition, a significant increase in SO2 and, in some cases, NOx

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[42] This equates with a 2.9% increase in heat input at each boiler.

is also considered to be significant for PM2.5. *Id.* For greenhouse gas emissions, a significant emission increase is defined as 75,000 tons per year of "CO2 equivalent emissions." 40 C.F.R. § 52.21(b)(49)(ii) and (iii).

A "significant net emissions increase" is simply a "net emissions increase" that is "significant." A "net emissions increase" involves an arithmetic determination of whether a project will result in an emissions increase by adding all the emissions increases that will result from a project and then adding and/or subtracting all contemporaneous, creditable emission increases and emission decreases. The definition of "net emissions increase" allows limitations requiring actual emission reductions to be credited if made enforceable as a practical matter. 40 C.F.R. § 52.21(b)(3). And "baseline actual emissions" as defined at 40 C.F.R. § 52.21(a)(2)(iv)(c) are used to evaluate emissions prior to the performance of any project in question.

In projecting future actual emissions when there is a capacity increase, such as what Entergy has requested in this permit action, future emissions must be projected for ten years following the date the unit resumes normal source operation. *See* 40 C.F.R. § 52.21(b)(41)(i). The "projected actual emissions" are to be based on the maximum annual rate at which a unit is projected to emit a pollutant in the ten years following the change, when a project increases capacity, and the following requirements must be taken into account in the projections:

> (a) [The owner] shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved State Implementation Plan; and
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> (b) [The owner] shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions; and

> (c) [The owner] shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth.

40 C.F.R. § 52.21(b)(41)(ii).

Exclusions of emission increases due to demand growth are only allowed if the increase in demand is completely unrelated to the project. *New York v. United States EPA ("New York I")*, 413 F.3d 3, 31-33 (D.C. Cir. 2005). In this case, where the company has requested an increase in allowable heat input capacity by 2.9% which will in turn allow for increased electricity generation, it would be impossible for Entergy to separate demand from the projected emission increases which represent and reflect a change in the method of operation. *Id.* at 32. Additionally, Entergy could not have legally accommodated heat input capacities above 8700 during the baseline period (due to the restrictions imposed by the federally enforceable heat input capacity limit discussed *supra*), which is a necessary pre-requisite to excluding any emission increases as unrelated to the project. 40 C.F.R. § 52.21(b)(41)(ii)(c). Further, it is possible that the units could also not physically accommodate the increased heat input and coal throughput during the baseline period, if physical changes were made to the turbines and/or the boilers to accommodate the increased heat input, which seems likely as discussed *supra*. For these reasons, Entergy would not have been able to exclude any projected emission increase in evaluating whether the increase in allowable heat input capacity of the White Bluff boilers would result in a significant emission increase.

Because of the high emission rates of SO2 and NOx at the White Bluff boilers, it would

not take many hours of operation at a 2.9% increase in permitted heat input capacity for the units to be projected have significant (*i.e.*, greater than 40 ton per year) emission increases of SO2 and NOx. Sierra Club projects that the units would only need to operate between 500-600 hours per year at 8950 MMBtu/hr (*i.e.*, an increase of 250 MMBtu/hr above the currently allowable heat input capacities of 8700 MMBtu/hr) to cause significant increases of SO2 and NOx at the White Bluff facility.[43] That means if the units operate at the increased hourly heat input capacity during 6-7% of the hours in a year, there would be significant emission increases of SO2 and NOx at each unit. Given that Entergy must project future emissions for ten years (because the permit change reflects an increase in design capacity) and because the company must evaluate the highest level of business activity, it is very likely that a significant emission increase of at least SO2 and NOx would be projected. White Bluff Unit 1 averaged over 3,000 hours per year at or above its 845 MW rating and White Bluff Unit 2 averaged over 3800 hours per year at or above its 845 MW rating in 2009-2010. Presuming that maximum heat input to the boilers equates to maximum hourly electrical generation of the units, there can be no doubt that the units would operate at least 500-600 hours more at the increased heat input capacity that would be allowed under the draft permit revision. Not only should Entergy have projected significant increases for SO2 and NOx for its requested heat input capacity and coal throughput increase, it also should have projected significant increases in PM2.5 because any increase in emissions that is significant for SO2 is also be significant for PM2.5. 40 C.F.R. § 52.21(b)(23)(i).

It is also probable that a significant emission increase of greenhouse gas emissions *(i.e.*,

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[43] This was determined assuming the units emit SO2 and NOx at their current average emission rates of, on average between the two units, 0.6 lb/MMBtu for SO2 and 0.28 lb/MMBtu for NOx according to data in EPA's Clean Air Markets Database.

an increase of at least 75,000 tons) would be projected at the White Bluff facility. 40 C.F.R. § 52.21(b)(49)(iii). If each unit operated was projected to operate approximately 2,900 hours at the requested heat input capacity of 8950 MMBtu in a year after the project, then there should have been a 76,000 ton per year increase in CO2 at each unit.[44] Given that the units each have operated at least 3,000 hours per year at or above the units' 845 MW rating and that maximum hourly heat input typically occurs with maximum hourly generation, it is very likely that Entergy would have projected a significant emission increase of greenhouse gas emissions at each White Bluff unit with the requested increase in heat input capacity and coal throughput.

Not only should the requested 2.9% increase in the allowable heat input capacity of the White Bluff boilers be projected to result in a significant emissions increase of SO2, NOx, PM2.5 and also likely greenhouse gases, the requested increase in allowable heat input capacity should also be projected to result in a significant net emissions increase of these pollutants. That is because there are no credible emission reductions of SO2, NOx, PM2.5 or greenhouse gas emissions that could be credited in an analysis of net emissions increase.

ADEQ has suggested that emissions will not increase because of the existence of the annual coal throughput limit in Condition VI.14 of the Final White Bluff Title V Renewal Permit. *See* August 2012 ADEQ Final Response to Comments at 3 ("The Permit that is the subject of this appeal will retain its annual coal throughput limitation of 9.2 million tons. As such, there will be no permitted increase to the coal-burning capacity of the White Bluff facility boilers.") (Ex. 76). The annual plantwide coal throughput limit does not, however, provide any

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[44] This was determined based on actual CO2 emission rates which averaged 0.105 tons/MMBtu at each unit in 2009-2010 according to data in EPA's Clean Air Markets Database.

assurances that actual emissions will not increase as a result of the allowable increase in hourly heat input capacity and hourly coal throughput of each White Bluff unit. As discussed above, PSD applicability is to be determined based on projected changes in actual emissions.

E. Summary

The Final White Bluff Title V Renewal Permit (No. 0263-AOP- R7) removes, relaxes, and/or revises federally enforceable limitations on the heat input and coal burning capacity of the White Bluff boilers and allow for a significant capacity increase at each White Bluff unit. Absent a comprehensive analysis demonstrating that allowing for such changes in the method of operation would not subject White Bluff Units 1 and 2 to PSD permitting requirements as major modifications, this permit cannot lawfully be issued. Had ADEQ done such an analysis in accordance with federal and state PSD regulations, ADEQ would have found that Entergy's requested 2.9% increase in heat input capacity of the White Bluff boilers would result in significant emission increases and significant net emissions increases of SO2, NOx, PM2.5 and probably also greenhouse gases. Sierra Club raised the issues discussed above in its November 23, 2011 comment letter to ADEQ (Ex. 67), although this petition also addresses both of ADEQ's responses to comments, which were clearly not available for public comment with the draft permit.

For all of the reasons stated above, the Final White Bluff Title V renewal permit is unlawful as written and the Administrator is obligated to object to it.[45]

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[45] In its August 2012 Final Response to Comments at 5, ADEQ appears to vaguely assert that Sierra Club's comments addressing the relaxation of the heat input limit are untimely and ineffective. ADEQ alleges that Sierra Club is using this permitting process to object to unnamed prior Title V permits and that because those prior unnamed permits underwent notice and public comment in which Sierra Club failed to raise certain specified issues – presumably pertaining to

Issue #3: The Administrator Must Object to the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) Because It Fails to Identify and Include All Applicable PSD Requirements Derived and Imposed as a Consequence of the Economizer Replacements at White Bluff Units 1 and 2 Which Triggered PSD Review.

In 2006, Entergy notified ADEQ that it intended to replace the economizer section of the Unit 1 boiler at White Bluff.[46] In 2007, Entergy notified ADEQ that it intended to replace the economizer section of the Unit 2.[47] In these submittals to ADEQ, Entergy provided calculations of actual-to-projected future actual emissions after the replacement of the economizers to determine applicability to PSD permitting requirements, and the company projected significant emission increases of SO2 and NOx at both units, as well as significant increases in PM10, PM, and fluorides at White Bluff Unit 1.[48] However, it appears that Entergy claimed that its projected emission increases were due to demand growth and not due to the economizer projects. As

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the heat input arguments asserted herein -- Sierra Club has "waived any objection it may now have to the enforceable limits and conditions that are a part of those prior permits," which presumably means the heat input arguments asserted herein. *Id.* ADEQ is wrong. With regard to renewal permits as opposed to Title V modification permits, comments may address any aspect of the permit whatsoever. *In the Matter of Wisconsin Public Service Corporation - Weston Generating Station*, Permit No. 73700902 & P02, Petition No. V-2006-4, Order at 5-7 (Adm'r December 19, 2007) (Ex. 89). Accordingly, it is entirely appropriate for Sierra Club to raise the heat input issues and other related issues in this context, regardless of whether they were commented on or addressed in some other context.

[46] *See* July 31, 2006 letter from Entergy to ADEQ regarding the economizer replacement at White Bluff Unit 1 (Ex. 22).

[47] *See* August 8, 2007 Letter from Entergy to ADEQ Regarding Economizer Replacement at White Bluff Unit 2 (Ex. 23). Note that, despite several state Freedom of Information Act requests to ADEQ for correspondence regarding White Bluff and specifically asking for this August 8, 2007 letter, ADEQ never provided it to Sierra Club. However, Entergy provided it to EPA in response to a Clean Air Act Section 114 Information Request, and Sierra Club recently obtained the August 8, 2007 letter from EPA via a federal Freedom of Information Act request.

[48] *See* Exs. 22 and 23 at page 1 of Actual to Future Projected Actual calculations.

explained below, Entergy should have projected significant emission increases and significant net emission increases of these pollutants due to the economizer replacement projects and, thus, these projects should have required a PSD permit including application of BACT at each unit before proceeding with the economizer replacements. Therefore, the White Bluff Title V permit is unlawful as it fails to include all PSD requirements including BACT applicable to the White Bluff boilers pertaining to the economizer replacements at each unit. Sierra Club raised this issue in its January 10, 2012 comment letter to ADEQ on the draft White Bluff Title V renewal permit. *See* 1/10/12 Sierra Club's Additional Comments on the Draft Title V Renewal Permit for the Entergy Arkansas White Bluff Plant (Draft Permit No. 0263-AOP-R7) at 5-36 (Ex. 68).[49]

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[49] In regard to NSR/PSD issues relating to emission increases, Sierra Club's comments relied in the first instance on emission calculations provided by Entergy to establish the proper baseline and projected future actual emissions to show an emission increase, and those calculations, which included Entergy's claimed net emission increases (and would have included decreases if there were any) that would be included in a netting analysis, were attached to Sierra Club's comments to ADEQ, *see* July 31, 2006 Letter from Entergy to ADEQ Regarding Economizer Replacement at White Bluff Unit 1 at pdf 3 (Ex. 15), or were attached to the initial petition to EPA once the Entergy letter and associated calculations were obtained from EPA via a FOIA request (which in turn had obtained the letter from Entergy via a Clean Air Act Section 114 information request). *See* August 8, 2007 Letter from Entergy to ADEQ Regarding Economizer Replacement at White Bluff Unit 2 at pdf 4-5 (Ex. 23). Sierra Club asserted in its comments that Entergy did not provide an adequate explanation in its emission calculations to justify the exclusion of its projected emission increases as due to demand growth. 11/23/11 Sierra Club's Comments on the Draft Title V Renewal Permit for the Entergy Arkansas White Bluff Plant (Draft Permit No. 0263-AOP-R7) at 19 (Ex. 67). ADEQ did not provide any further support for Entergy's demand growth exclusion, other than to speciously contend in its May 2012 Response to Comments that "[s]imple factors such as weather and energy demands which greatly affect these calculations were not included in the comments." May 2012 ADEQ Response to Comments at 6-7 (Ex. 74). In ADEQ's Final Response to Comments, ADEQ does not even recognize that it evaluated Sierra Club's arguments relating to the demand growth exemption. August 2012 ADEQ Final Response to Comments at 2-6 (Ex. 76). With regard to the increased heat input and coal throughput issue, Sierra Club explicitly stated that there had been "no credible emission reductions of SO2, NOx, PM2.5 or greenhouse gas emissions that could be credited in an analysis of net emissions increase." 11/23/11 Sierra Club's Comments on the Draft Title V Renewal Permit for the Entergy Arkansas White Bluff Plant (Draft Permit No.

Sierra Club petitions EPA to object to the Final White Bluff Title V permit because it fails to include the applicable PSD requirements including BACT emission limits applicable to the economizer replacement projects at both White Bluff Unit 1 and Unit 2. The details of these projects and why they should be considered major modifications under the PSD regulations are provided below.

A. Title V Requires ADEQ to Have Included a Compliance Schedule in the Final Title V Operating Permit for Prior PSD Violations at White Bluff.

All sources subject to Title V must have a permit to operate that "assures compliance by the source with all applicable requirements." *See* 40 C.F.R. § 70.1(b); Clean Air Act ("CAA" or the "Act") § 504(a), 42 U.S.C. § 7661c. To meet this requirement, every Title V permit application must provide "a description of all applicable requirements" and must disclose any violations at the facility. APCEC Reg. 26.402(4)(a) and (8)(a), (b)(iii) and (c) (iii); 42 U.S.C. § 7661b(b); 40 C.F.R. §§ 70.5(c)(4)(I), (5), (8). Arkansas and federal law define "applicable requirements" to include:

> 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 that implements the relevant requirements of the Act, including any revisions to that plan promulgated in 40 CFR part 52.

APCEC Reg. 26, Chapter 2 (definition of "applicable requirement"); 40 C.F.R. § 70.2. This definition encompasses the requirement for new and modified major stationary sources to obtain PSD permits that fully comply with all applicable PSD requirements under the Act and the Arkansas SIP, including the requirements to apply BACT and to perform air quality demonstrations. *See generally* CAA §110(a)(2)(C), 160-69, 173; 40 C.F.R. § 52.21 *et seq.*;

0263-AOP-R7) at 20 (Ex. 67).

APCEC Reg.19.901 *et seq.*

For any applicable requirements, including PSD requirements and other preconstruction requirements, for which the source is not in compliance at the time of permit issuance, the source's application must provide a narrative description of how the source intends to come into compliance with the requirements. APCEC Reg. 26.402(8)(b)(iii); 42 U.S.C. § 7661b(b); 40 C.F.R. § 70.5(c)(8)-(9). The application must further propose a compliance schedule for any applicable requirements for which the source is not in compliance. APCEC Reg. 26.402(8)(c)(iii); 40 C.F.R. § 70.5(c)(8)(iii). If any statements in the application were incorrect, or if the application omits relevant facts, the applicant has an ongoing duty to supplement and correct the application. APCEC Reg. 26.409; 40 C.F.R. § 70.5(b).

There is no indication that ADEQ adequately evaluated Entergy's submittals or otherwise made PSD applicability determinations regarding the recent replacements of economizers at White Bluff Units 1 and 2 in 2006 and 2007, respectively, prior to the commencement of those projects. As shown below, these modifications should have triggered PSD for NOx and SO2 at each unit and also for PM10, PM, and fluorides at White Bluff Unit 1. Entergy was thus required to obtain a PSD permit imposing BACT limits for emissions and to comply with all other PSD-related preconstruction requirements for the economizer replacement at each unit. Because ADEQ failed to adequately evaluate the White Bluff Plant's compliance with the PSD requirements of the Clean Air Act and the Arkansas SIP and the PSD violations are ongoing, the Final White Bluff Title V Renewal Permit cannot be issued because a compliance schedule to address these ongoing PSD violations has not been included in the permit.

B. Entergy's Analysis of PSD Applicability for the Economizer Replacement

Projects at White Bluff Units 1 and 2 Do Not Comport with the Applicable PSD Regulations and Are Both Legally and Technically Flawed.

1. Regulatory Background of PSD Program.

The Clean Air Act was passed 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 the United States' population. 42 U.S.C. § 7401(b)(1). Congress intended to "speed up, expand, and intensify the war against air pollution in the Untied States with a view to assuring that the air we breathe throughout the Nation is wholesome once again." *Wis. Elec. Power Co. v. Reilly,* 893 F.2d 901, 909 (7th Cir. 1990) (quoting H.R. Rep. No. 91-1146, at 1 (1970), *as reprinted in* 1970 U.S.C.C.A.N. 5356, 5356)). As its name implies, the Prevention of Significant Deterioration program in Part C of the Clean Air Act, 42 U.S.C. §§ 7470-7492, creates a program to prevent those areas currently attaining the minimum national air quality standards from deteriorating. The PSD provisions prohibit a major emitting facility from being constructed or modified unless, among other requirements, it: (1) obtains a PSD permit, 42 U.S.C. § 7475(a)(1); (2) by a permitting agency and through a public hearing, 42 U.S.C. § 7475(a)(2), has demonstrated that it will not cause or contribute to a violation of NAAQS or a "maximum allowable increase" over existing pollution levels ("increment"), 42 U.S.C. § 7475(a)(3); and (3) meets pollution limits based on "best available control technology" ("BACT"), 42 U.S.C. § 7475(a)(4).

Although Congress intended the Clean Air Act to clean up old, polluting facilities, it recognized that it was not economically feasible to retrofit pollution controls on all existing sources. Therefore, Congress "grandfathered" existing facilities, effectively exempting them from compliance with new regulations until the facilities were modified. *Alabama Power v.*

Costle, 636 F.2d 323, 400 (D.C. Cir. 1979); *United States v. Murphy Oil USA, Inc.*, 155 P.5upp.2d 1117, 1137 (W.D. Wis. 2001) (citing *Wisconsin Electric Power Co. v. Reilly (WEPCO)*, 893 F.2d 901, 909 (7th Cir. 1990)). This "grandfathering" was intended to be temporary – not "to constitute perpetual immunity" from all standards under the PSD program. *Alabama Power*, 636 F.2d at 400; *WEPCO*, 893 F.2d at 909 ("But Congress did not permanently exempt existing plants from these [PSD] requirements; section 7411 (a)(2) provides that existing plants that have been modified are subject to the Clean Air Act programs at issue here."); *U.S. v. Ohio Edison* Co., 276 F. Supp.2d 829, 850 (S.D. Ohio 2003) (Congress did not intend that existing sources be granted perpetual immunity from installing modern pollution controls).

As previously stated, Arkansas has incorporated by reference the federal PSD regulations at 40 C.F.R. § 52.21 *et seq.* into state regulations. However, although the state had adopted EPA's 2002 revisions to its PSD regulations[50] as part of Arkansas Reg. 19.904 at the time of the Unit 1 economizer replacement, EPA had not yet approved those revised regulations as part of the Arkansas SIP. In fact, EPA did not approve Arkansas' current PSD regulations which reflect EPA's 2002 PSD rule revisions as part of the Arkansas SIP until April 12, 2007 (72 Fed. Reg. 18394 (April 12, 2007)), but construction commenced on the Unit 1 economizer replacement on approximately September 15, 2006 and was completed by approximately November 19, 2006.[51] Therefore, the White Bluff Unit 1 economizer project must be evaluated with reference to the

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[50] 67 Fed. Reg;. 80186-80289 (December 31, 2002).

[51] *See* Entergy's 2006 FERC Form 1 Supplement Annual Report at Supp E-5 (Ex. 24D).

prior version of the Arkansas SIP's Reg. 19.901 *et seq.*; 40 C.F.R. § 52.21 *et seq.* (1994).[52] On the other hand, the Unit 2 economizer project, upon which construction commenced after April 2007, must be evaluated under the most recent SIP-approved version of Reg. 19.901 *et seq.*; 40 C. F. R § 52.21 *et seq.* *See* 40 C.F.R. § 52.170(c).

Some of the relevant differences between the two sets of PSD regulations include that the 1994 version of the PSD regulations approved into the SIP required the baseline emissions to be based on the two years of emissions prior to the modification, unless a different time period was approved by the permitting authority as more representative of normal source operations. 40 C.F.R. §§ 52.21(b)(3)(i)(a) and (21)(ii) (1994). Under the PSD regulations approved in the

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[52] This version of the state's PSD rules was approved by EPA on October 16, 2000 (65 Fed. Reg. 61103 (October 16, 2000). ADEQ maintains that for the purpose of evaluating whether this work triggered PSD, the regulations which are applicable to such an analysis were the Arkansas PSD regulations which were approved at that time - -that is, the newer version of the PSD regulations – and not the older version of the Arkansas PSD regulations, which still constituted the EPA-approved SIP at this juncture. August 2012 ADEQ Final Response to Comments at 10 (Ex. 76). This position is clearly wrong. As a matter of law, the EPA-approved SIP is the SIP until it is revised with EPA approval and even when a SIP revision is pending, the EPA-approved SIP continues to govern. *General Motors Corp. v. United States*, 496 U.S. 530, 540 (1990) ("Both this Court and the Courts of Appeals have recognized that the approved SIP is the applicable implementation plan during the time a SIP revision proposal is pending."); *Friends of the Earth v. Carey*, 535 F.2d 165, 178-79 (2d Cir. 1976), cert. denied, 434 U.S. 902 (1977) (procedure set forth in CAA for revision of SIP is exclusive method by which a SIP can be amended); *Sierra Club v. Tennessee Valley Authority*, 430 F.2d 1337, 1347 (11th Cir. 2005) (quoting *Train v. Natural Res. Def. Council, Inc.*, 421 U.S. 60, 92 (1975) ("[A] polluter is subject to existing requirements until such time as he obtains a variance, and variances are not available under the revision authority until they have been approved by both the State and the Agency."); *United States v. Ford Motor Co.*, 814 F.2d 1099, 1103 (6th Cir.1987) (holding that "invalidation of a SIP on technical grounds by a state court ... cannot be given effect, because ... revisions and variances of properly promulgated SIPs require EPA approval"); and 40 C.F.R. § 51.105 ("Revisions of a plan, or any portion thereof, will not be considered part of an applicable plan until such revisions have been approved by [EPA] in accordance with this part."))). Accordingly, the 2000 version of the PSD regulations provide proper framework for analysis threshold PSD applicability with regard to any alleged major modification occurring during any time that those SIP rules were effective.

Arkansas SIP in 2007, baseline emissions are governed by the definition of "baseline actual emissions" which allows any consecutive 24 month period in the five years prior to commencement of actual construction on a project to be used as baseline. 40 C.F.R. §§ 52.21(a)(2)(iv), (b)(3)(i)(b), and (b)(48)(i) (2007). While both sets of PSD regulations allow post change emissions to be based on future actual emissions for electric utility steam generating units, the 1997 regulations approved in the Arkansas SIP makes clear that such projections of "representative actual annual emissions" can only be used in a PSD applicability determination if the company reports post-change emissions data demonstrating that the modification did not result in an emissions increase for at least five years following the modification. 40 C.F.R. §§ 52.21(b)(23)(v) (1994). Otherwise, applicability to PSD for a modified source is to be based on an actual-to-potential emissions test. 40 C.F.R. §§ 52.21(b)(23)(iv) (1994).

Although there are some significant differences in the two versions of the Arkansas SIP's PSD rules, there are two fundamental components to determining applicability of these modifications at the White Bluff units to PSD. To constitute a "major modification" which triggers PSD applicability: (1) there must "physical change or change in the method of operation;" and (2) there must be a significant emission increase. More specifically, under the prior version of the Arkansas SIP's Reg. 19.901, there must be a "significant net emissions increase," APCEC Reg. 19.904; 40 C.F.R. § 52.21(b)(2)(i) (1994), and under the most recent version of the Arkansas SIP, there must be both a "significant emissions increase" and a "significant net emission increase." APCEC Reg. 19.904; 40 C.F.R. § 52.21(a)(2)(iv)(a) (2007).

The term "physical change" is very broad. Congress intended that "any physical change" trigger the PSD program requirement, and intended "any physical change" to have an expansive

meaning. *New York v. EPA ("New York II")*, 443 F.3d 880, 885-87 (D.C. Cir. 2006) (holding that 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. As stated recently in *United States v. Cinergy Corp.*:

> The CAA defines the term 'modification' broadly as 'any physical change . . . which increases the amount of any air pollutant emitted . . . .' 42 U.S.C. § 7411(a)(4). As the Seventh Circuit has noted, the potential reach of this definition is broad and encompasses even the most trivial of activities.

495 F. Supp. 2d 892, 901-02 (S.D. Ind. 2007) (citing *WEPCO*, 893 F.2d at 905; *Alabama Power*, 636 F.2d at 400 (modification "is nowhere limited to physical changes exceeding a certain magnitude.")).

An exemption does exist in the definition of "major modification" for "routine maintenance, repair and replacement." APCEC Reg. 19.904; 40 C.F.R. § 52.21 (2) (iii)(a). However, this exemption is exceedingly narrow. *United States v. So. Ind. Gas & Elec. Co.*, 245 F. Supp. 2d 994, 1009 (S.D. Ind. 2003) ("Giving the routine maintenance exemption a broad reading could postpone the application of NSR to many facilities, and would flout the Congressional intent evinced by the broad definition of medication.").[53] To fall within this

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[53] EPA's September 9, 1988 Memorandum from Don R. Clay, USEPA, to David A. Kee, "Applicability of Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) Requirements to the WEPCO Power Company Port Washington Life Extension Project."("1988 Clay Memo") at 3 (Ex. 65) reinforces the narrow scope of the routine maintenance exception, stating: "[t]he clear intent of the PSD regulations is to construe the term "physical change" ***very broadly***, to cover ***virtually any significant alteration*** to an existing plant. This wide reach is demonstrated by the ***very narrow*** exclusion provided in the regulations." (emphasis added).

exception, the burden[54] is on the source to demonstrate that the project in question satisfies a rigorous four-factor test which assesses the nature and extent, purpose, frequency and cost of the work. *WEPCO*, 893 F.2d at 910 (quoting 1988 Clay Memo (Ex. 65); *United States v. Cinergy*, 2006 WL 372726, *4 (S.D. Ind. Feb. 16, 2006) ("The party claiming the benefit of an exemption to compliance with a statute bears the burden of proof as to the exemption.") (citing *United States v. First City Nat'l Bank of Houston*, 386 U.S. 361, 366 (1967)); *Ohio Edison*, 276 F. Supp. 2d at 856; *Sierra Club v. Morgan,* No. 07-C-251-S 2007 U.S. Dist. LEXIS 82760 at *34 (W.D. Wis. 2007); *Nat'l Parks Conservation Ass'n v. TVA*, 618 F. Supp. 2d 815, 824 (E.D. Tenn. 2009)("Defendant TVA bears the burden of proof as to the applicability of the RMRR exception in this case."); *United States v. E. Ky. Power Coop., Inc.*, 498 F. Supp. 2d 976, 995 (E.D. Ky. 2007); *In the Matter of Tennessee Valley Authority, Paradise Fossil Fuel Plant, Drakesboro, Kentucky*, Title V Air Quality Permit # V-07-018 R1, Petition No.: IV-2010-1, Order at 8-14 (Adm'r May 2, 2011).[55] As stated in *Ohio Edison*, 276 F. Supp. 2d at 834:

> Routine maintenance, repair, and replacement occurs regularly, involves no permanent improvements, is typically limited in expense, is usually performed in

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[54] Similarly, through the permitting application process, Entergy had the burden of proving that the routine maintenance exemption applied to both economizer projects and of providing the supporting basis for such an exemption. APCEC Reg. 26.402 (B)(6); 40 C.F.R. § 70.5(c)(6). It has failed to meet its burden of proof and has not included any supporting documentation for such an exemption in the present permit application for either the Unit 1 or 2 economizer replacement projects.

[55] This order sets out EPA's reasonable interpretation of the routine maintenance, repair and replacement exemption and demonstrates EPA's consistency over time in assessing the application of that exemption. *Id.* at 8-14. When the routine maintenance analysis discussed by EPA in the TVA Paradise Order is applied to the economizer projects at White Bluff (or to economizer replacements generally, which are quite extensive, expensive and rarely performed at any individual plant), it is clear that the project cannot lawfully be considered routine maintenance.

> large plants by in-house employees, and is treated for accounting purposes as an expense. In contrast to routine maintenance stand 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.

Ohio Edison, 276 F. Supp. 2d at 834 (citations omitted).

The second part of a PSD applicability analysis involves an assessment of emissions increases under the applicable rules. As stated previously, under the prior version of APCEC Reg. 19.904, there must be a "significant net emissions increase," APCEC Reg. 19.904; 40 C.F.R. § 52.21(b)(2)(i) (1994), and under the most recent version of the Arkansas SIP, there must be both a "significant emissions increase" and a "significant net emission increase." APCEC Reg. 19.904; 40 C.F.R. § 52.21(a)(2)(iv)(a) (2007).

2. The Economizer Replacements at White Bluff Units 1 and 2 Were Not Routine Maintenance, Repair, or Replacement.

There is no question that the 2006 and 2007 economizer replacement projects at White Bluff Units 1 and 2 constituted a "physical change" at each unit. And this work was clearly not exempt from PSD applicability as "routine maintenance" work despite the fact that Entergy did refer to the economizer replacements as "maintenance projects."[56]

Other than referring to the projects "maintenance," Entergy submitted no documentation to ADEQ, at the time the Unit 1 or Unit 2 economizer replacement projects were noticed or commenced or in the context of its actual-to-projected future actual emissions analysis submitted to ADEQ, that would support a claim that this project constituted routine maintenance according

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[56] *See* July 31, 2006 letter from Entergy to ADEQ regarding the economizer replacement at White Bluff Unit 1 (Ex. 22) and August 8, 2007 letter from Entergy to ADEQ regarding the economizer replacement at White Bluff Unit 2 (Ex. 23).

to the applicable four factor test set forth in the Clay Memo and as elaborated on in relevant EPA applicability determinations and orders and in federal case law. Based on a review of the pertinent case law and the fact that Entergy failed to provide any documentation to ADEQ sufficient to support such a finding, it is beyond question that this project could not legitimately satisfy the routine maintenance exemption. *See, e.g., Morgan*, 2007 U.S. Dist. LEXIS 82760 at *41-42 (replacement of economizers every 24 years "can hardly be considered 'routine.'"); *see generally WEPCO*, 893 F.2d at 909-11, *Cinergy,* 495 F. Supp. 2d at 933-948; *United States v. S. Indiana Gas and Elec. Co. (SIGECO)*, 245 F. Supp. 2d 994, 1008 (S.D. Ind. 2003); *Ohio Edison*, 276 F. Supp. 2d at 834; *In the Matter of Tennessee Valley Authority, Paradise Fossil Fuel Plant, Drakesboro, Kentucky*, Title V Air Quality Permit # V-07-018 R1, Petition No.: IV-2010-1, Order at 8-14.

Nonetheless, the lack of any evidence that ADEQ evaluated the projected emissions increase calculations that were submitted for the White Bluff Unit 1 or Unit 2 economizer projects suggests that ADEQ may have made a legally erroneous routine maintenance decision regarding these economizer replacement projects which, once made, would have obviated the need for ADEQ to go further in the PSD analysis and evaluate emission increases. While ADEQ does not directly assert that the economizer replacements were routine maintenance, it does state in its Final Response to Comments at 14 (Ex. 76) that the "[r]eplacement of economizers is ***not an unusual activity***." (emphasis added). The specific reference to the term "unusual activity" seems to imply, albeit vaguely, that ADEQ agrees with and has adopted the fundamentally flawed position on routine maintenance set forth in *Nat'l Parks Conservation Ass'n, Inc. v. TVA*, 2010 U.S. Dist. LEXIS 31682, at *72 (E.D. Tenn. Mar 31, 2010), which inappropriately turned

the limited routine maintenance exemption on its head by applying the exemption to a broad category projects so long as they were "not unusual" or exceptional. The *National Parks* decision is an outlier which reflects an erroneous interpretation of the routine maintenance exception that is inconsistent with a long line of EPA determinations on the routine maintenance question and pertinent case law. ADEQ's tacit approval of that decision[57] and implication that perhaps White Bluff's economizer replacements could be considered routine maintenance should be addressed by EPA through an objection so that ADEQ is aware that that non-binding and unpersuasive Tennessee district court decision should not be relied upon define routine maintenance in Arkansas and to confirm that projects as extensive as the economizer projects in question here cannot be treated as routine maintenance.

It is inconceivable that projects as expansive, expensive and as infrequently performed as the economizer replacements at White Bluff Units 1 and 2 could ever be considered routine maintenance under a rational application of the four factor test. First, according to Entergy's response to a Sierra Club data request in a 2009 proceeding before the Arkansas Public Service Commission (APSC), the capital cost of the economizer/ductwork replacements was $16.3 million at Unit 1 and $16.5 million at Unit 2.[58] Entergy has also identified the economizer

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[57] *See* August 2012 ADEQ Final Response to Comments at 11 (approvingly citing to *National Parks* and indicating (despite it only being a district court decision) that it had set up intra-and extra-Circuit splits on the routine maintenance issue) (Ex. 76).

[58] *See* Response of Entergy-Arkansas, Inc., to Sierra Club's Fourth Set of Data Requests, Response to Request 4-1.e. (Docket No. 09-024-U, White Bluff Declaratory Order) (Ex. 5).

replacements as capital expenditures.[59] Replacement of the economizers took a long time, occurring over 9 week outages at each unit.[60]

Further, it is very likely that an economizer with a substantially different design was installed at both of the White Bluff units, as was done at Entergy's Independence units. At the Independence plant, the original economizers for Units 1 and 2 were staggered, fin-tube economizers, and the selection of this design resulted in load limitations due to ash pluggage.[61] In response, Entergy replaced the Independence Units 1 and 2 economizers with a substantially different in-line tube design.[62]

Similarly, White Bluff Units 1 and 2 were also experiencing many derates due to ash pluggage in the economizer in the years before replacement.[63] Given that the White Bluff plant and the Independence plant were owned by the same company at the time of construction (Arkansas Power & Light Company) and were designed is very similar to each other, it is very likely that the original White Bluff economizers also incorporated a staggered, fin-tube design and that those economizers at White Bluff Units 1 and 2 were replaced with bare tube, in-line design economizers. Entergy projected improvements in heat rate with the economizer

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[59] *Id.*

[60] *See Entergy's* 2006 and 2007 FERC Form 1 Supplement Annual Report at Supp E-5 (Exs. 24D and 24E).

[61] *See* Excerpt of Arkansas Electric Cooperative Corporation's Loan Guarantee Request to the Rural Utilities Service, dated August 10, 2009, at 195-196 (Batestamp AECC 000263-000264). (Ex. 26)

[62] *Id.* at 195.

[63] *See* Entergy's 2003-2006 FERC Form 1 Reports to the APSC that are publicly available on the APSC website (Exs. 24A-24D).

replacements at White Bluff Units 1 and 2.[64] which would likely only occur if a different design economizer was being installed. Indeed, Entergy's notification of the Independence Unit 2 economizer replacement stated that the project was "identical to the projects completed for Entergy's White Bluff Plant, Units 1 & 2."[65] As with the economizer replacements at White Bluff Units 1 and 2, Entergy anticipated to derive a heat rate improvement from the Independence Unit 2 economizer replacement.[66] Given all of these similarities between the Independence and White Bluff economizers and Entergy's claims of improved heat rate, it is almost a certainty that the White Bluff economizers were replaced with a different design economizer.

The replacement of one economizer with another with a different design cannot be considered a routine change. Rather, such work constitutes a fundamental design change that is not even arguably subject to the routine maintenance exemption because it does not constitute maintenance, repair or replacement.[67]

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[64] *See* Heat Rate Improvement Attachments of Entergy's July 31, 2006 and August 7, 2007 submittals to ADEQ (Exs. 22 and 23).

[65] *See* September 19, 2008 Submittal from Entergy to ADEQ (Ex. 27).

[66] *Id.* at Attachment with heading "ISES2 Heat Rate Improvement Study."

[67] As touched on above, these projects should have been expected to result in increased availability (and higher emissions on an annual basis). The economizer replacements should also have been expected to result in increased generating capacity due to the elimination of historic load limitations related to economizer plugging problems which ultimately stemmed from a sub-optimal economizer design. Once those load limitations and forced outages were eliminated, more coal would be burned to take advantage of the increased generating capacity and the increased availability of the unit, and thus more air pollution would be emitted. Also, with a different economizer design and the projected improvements in heat rate, the units would likely have been dispatched more frequently due to being more fuel efficient.

For the reasons described above, the replacement of the economizers at White Bluff Units 1 and 2 cannot be considered routine maintenance.

3. Entergy's PSD Applicability Analyses for the Economizer Replacements at White Bluff Units 1 and 2 are Legally and Technically Deficient.

In its July 31, 2006 submittal to ADEQ regarding the economizer replacement at White Bluff Unit 1, Entergy submitted calculations which it claimed demonstrated "this project [would] not result in a significant emission increase."[68] While Entergy acknowledged that "the actual to projected actual test shows a significant increase in emissions," it claimed that "further analysis demonstrated the emission increase [was] not attributable to this project."[69] Instead, Entergy argued that "the project [would] result[] in an actual decrease in emissions relative to future projected emission without undertaking the project."[70] Entergy attributed its projected actual emissions to "normal economic activity including projected fuel prices and system electricity demand."[71]

In an August 8, 2007 submittal to ADEQ regarding the economizer replacement at White Bluff Unit 2, Entergy projected significant emission increases after completion of the economizer

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[68] *See* July 31, 2006 Letter from Entergy to ADEQ at 1 (Ex. 22).

[69] *Id.*

[70] *Id.* It should be noted that as part of its argument to ADEQ for why PSD was not triggered, Entergy presented information which purportedly shows what the future actual emissions would be assuming the project was ***not*** performed. This is not an element of the regulatory test for determining whether a major modification has occurred and only creates confusion as to what the relevant analysis should be to assess PSD applicability.

[71] *Id.*; *see also* February 25, 2008 Letter from Entergy's M. Bowles to ADEQ's T. Rheaume Regarding Unit 1 Economizer at 1 (Ex. 28) (correspondence after project was completed recognizing increased emissions above baseline which Entergy attributed "to factors unrelated to the project" such as increased demand).

replacement at Unit 2 and claimed that the project could not cause those emission increases, as it claimed with Unit 1. Specifically, Entergy stated:

> While the actual to projected actual test shows a significant increase in emissions, further analysis demonstrates [sic] that the emissions increase is not attributable to this project. This is illustrated by comparing the future projected actual emissions of White Bluff Unit 2 without the project to the future projected actual emissions of the White Bluff Unit 2 with the project. This data shows the project results in an actual decrease in emissions relative to future projected emissions without undertaking the project. In other words, without this project, projected actual emissions will be higher simply due to normal economic activity including projected fuel prices and system electricity demand.

August 8, 2007 Submittal from Entergy to ADEQ at 1 (Ex. 23).

There is little information provided in Entergy's submittals to verify its analyses. In particular, no additional data has been provided to demonstrate that Entergy's projected increases in each unit's capacity factor was completely unrelated to the economizer replacement projects. Further, Entergy provided no analysis to show whether the increases in capacity factor could have been accommodated during the respective baseline period for each unit's economizer replacement project. While Entergy's projections of capacity factor appear to be based on a PROSYM analysis, no information on the assumptions used in the PROSYM analysis was specified and no copy of the analysis was provided. Without the details of what went into the projected future actual analyses, one cannot tell whether Entergy's analysis took into account any increased availability of the units or any increase in maximum production rate of the units due to the economizer replacement compared to baseline operations. Furthermore, one cannot determine if Entergy took into account the increase in unit dispatch with the improved heat rate which Entergy claims would occur with the economizer replacement at both White Bluff Units 1 and 2.

Based on records obtained from ADEQ, it does not appear that ADEQ objected to any of Entergy's contentions regarding this project and that nothing was done by ADEQ to determine whether the claims Entergy made were factually and technically supported or consistent with applicable law.[72] Entergy commenced construction on the economizer replacement project for White Bluff Unit 1 on approximately September 15, 2006. By approximately November 19, 2006, that construction work was completed and Unit 1 had commenced operations. Entergy commenced construction on the economizer replacement at White Bluff Unit 2 on approximately September 16, 2007 and completed construction on approximately November 18, 2007.[73]

After White Bluff Unit 1 was returned to service, Entergy submitted only one (1) of five (5) annual reports of emissions for Unit 1 that it had committed to provide to ADEQ. On February 25, 2008, Entergy submitted its first annual report covering 2007.[74] In the cover letter enclosing that report, Entergy stated:

> Since the original projected actual emission baseline average emission evaluation for this project indicted that there was not a "reasonable possibility" of a significant increase in emissions, Entergy is proposing to suspend submittal of these reports.

February 25, 2008 Letter from Entergy to ADEQ at 1 (Ex. 28). In this submittal, Entergy acknowledged that actual emissions had increased above baseline, but Entergy attributed the increase to "factors unrelated to the project" such as "increased demand for power." There is no

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[72] This was an egregious error on ADEQ's part as this project should have triggered the application of the Clean Air Act's PSD requirements to White Bluff Unit 1 and Unit 2.

[73] *See* Entergy's 2007 FERC Form 1 Annual Report at Supp. E-5 (Ex. 24E).

[74] February 25, 2008 Letter from Entergy's M. Bowles to ADEQ's T. Rheaume Regarding Unit 1 Economizer at 1 (Ex. 28).

record that Entergy submitted any additional post-project emission reports for the Unit 1 economizer replacement project.

It does not appear that Entergy submitted any annual reports to ADEQ after replacement of the economizer at White Bluff Unit 2. Entergy stated in its notification to ADEQ that there was not a "reasonable possibility" that a significant emission increase would occur as a result of the economizer replacement project, and thus Entergy presumed that the reporting provisions of 40 C.F.R. § 52.21(r)(6)(iv) did not apply.[75]

There a number of flaws in Entergy's PSD applicability analyses for the White Bluff Unit 1 and 2 economizer replacement projects, as discussed below.

a. *Flaws in Entergy's Determination of Baseline Emissions.*

In both of the PSD applicability analyses for the economizer replacement projects for White Bluff Units 1 and 2, Entergy's determination of baseline emissions was deficient.

For the Unit 1 economizer replacement, Entergy was required under the applicable Arkansas SIP to use the two years prior to the 2006 economizer replacement as reflective of baseline emissions unless ADEQ determined that a different baseline period was more representative of normal source operations. 40 C.F.R. § 52.21 (b)(21)(ii) (1994). To comply with this requirement, Entergy should have used the two years prior to commencing construction on the economizer replacement project as baseline, *i.e.*, 2004-2005. Instead, Entergy used 2003-2004 as baseline emissions for the Unit 1 economizer replacement. *See* July 31, 2006 Letter from Entergy to ADEQ, Attachment at 1 (Ex. 22). According to the applicable rule, if Entergy had sought and obtained a determination from the Administrator that its baseline period was

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[75] *See* Entergy's August 7, 2007 submittal to ADEQ at 1 (Ex. 23).

more representative, it could have properly used 2003 and 2004, *id.*, but no such determination was obtained.

In addition, Entergy's determination of baseline emissions for each of the economizer replacement projects are improperly inflated. During the 2003-2004 baseline period for the Unit 1 economizer project, White Bluff Unit 1 was being operated above its federally enforceable permit limit on maximum design heat input capacity of 8700 MMBtu/hr.[76] According to hourly heat input data submitted to EPA's Clean Air Markets Database, Unit 1 operated 2,353 hours (or 29% of the 2003 operating hours) above the allowable heat input capacity of 8700 MMBtu/hr in 2003, and the unit operated 2,376 hours (or 31% of its operating hours) above the allowable heat input capacity of 8700 MMBtu/hr in 2004.[77] During the 2004-2005 baseline period for the Unit 2 economizer project, Unit 2 operated 3,028 hours (or 37% of the 2004 operating hours) above the allowable heat input capacity of 8700 MMBtu/hr in 2004, and the unit operated 2,395 hours (or 31% of its operating hours) above the allowable heat input capacity of 8700 MMBtu/hr in

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[76] Section IV of the White Bluff operating permit specifies the heat input capacity of the White Bluff boilers as 8700 million BTU per hour. A copy of the operating permit that applied during the baseline period used by Entergy (Permit # 263-AOP-R3) is attached as Ex. 29. This limitation is in the prior operating permit for White Bluff as well. Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6) at 16, pdf 20 (Ex. 30).

[77] Based on hourly heat input data for White Bluff Unit 1 downloaded from EPA's Clean Air Markets Database at http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard. Heat input data is required to be measured under the Acid Rain Program along with emissions data, and that data is required to be submitted by Entergy to EPA. EPA posts that data in the Clean Air Markets Database. Note that the prior Title V permit for White Bluff Units 1 and 2 identifies the monitoring requirements of the Acid Rain Program in Appendix F of 40 C.F.R. Part 75 as the method for measuring hourly heat input. *See* Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6), Condition IV.23 at 24, pdf 28 (Ex. 30).

2005.[78] Thus, emissions during the baseline period are significantly higher than they would have been if each White Bluff unit had been operated in compliance with its heat input capacity limit. Entergy cannot lawfully rely on an inflated baseline emissions in a PSD applicability analysis. *See* October 1990 Draft New Source Review Workshop Manual at A.41-42, A.48; *see also* 40 C.F.R. § 52.21(b)(48)(i)(b). Entergy's baseline emissions for these project should have been adjusted downward to correspond to the White Bluff Units' allowable heat input capacity permit limit of 8700 MMBtu/hr before being compared to projected representative actual annual emissions.

Furthermore, Entergy's two year baseline period of actual SO2 and NOx emissions is also improperly inflated for the Unit 1 economizer replacement project because the emissions used were based on continuous emission monitoring system ("CEMS") data which included significant periods where Acid Rain Program 95% data capture requirements were not complied with.[79] Sierra Club has reviewed the data submitted by Entergy to EPA's Clean Air Markets Database ("CAMD") and found that in 2004, there were 1,128 hours of substituted hourly SO2 emissions data for White Bluff 1. When a significant amount of data from an Acid Rain CEMS is missing, the methodology used for data substitution requires a source to "conservatively"

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[78] Based on hourly heat input data for White Bluff Unit 2 downloaded from EPA's Clean Air Markets Database at http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction= emissions. wizard. Heat input data is required to be measured under the Acid Rain Program along with emissions data, and that data is required to be submitted by Entergy to EPA. EPA posts that data in the Clean Air Markets Database. Note that the prior Title V permit for White Bluff Units 1 and 2 identifies the monitoring requirements of the Acid Rain Program in Appendix F of 40 CFR Part 75 as the method for measuring hourly heat input. *See* Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6), Condition IV.23, at 24, pdf 28 (Ex. 30).

[79] *See, e.g.*, August 8, 2005 letter from ADEQ to Entergy re March 17, 2005 compliance inspection and related e-mails at 1-4 (Ex. 31).

estimate higher emissions for SO2 and NOx.[80] Since the actual emissions used in Entergy's baseline period to assess PSD applicability for this project included a significant portion of substituted data,[81] the baseline emissions overstate actual emission levels for the Unit 1 economizer project. Thus, the 2003-2004 baseline emissions data based on CEMS cannot be considered representative of normal source operation for White Bluff Unit 1. 40 C.F.R. § 52.21(b)(21)(ii).

For these reasons, Entergy's determinations of baseline emissions for both the White Bluff Unit 1 and Unit 2 economizer projects are flawed and unlawful.

b. *Entergy's Determinations of Future Actual Emissions After the Unit 1 and 2 Economizer Replacements Are Flawed and Do Not Comport with Applicable Law.*

There are many deficiencies in Entergy's projections of future actual emissions for the economizer replacements at White Bluff Units 1 and 2. Sierra Club commented on these deficiencies in great detail in its January 10, 2012 comment letter to ADEQ at 15-23, 26-36 (Ex. 68).

(1) The Unit 1 Economizer Replacement Project Should Be Evaluated on an Actual-to-Potential to Emit Basis Because Entergy Failed to Report Emissions for Five Years After the Economizer Replacement.

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[80] 40 CFR § 75.33 and § 75.34; *see also* U.S. EPA, Clean Air Markets Division, Plain English Guide to the Part 75 Rule, September 2005.

[81] *See* CAMD Data for White Bluff Unit 1 (2003 - 3rd Quarter 2009) (Ex. 32).

As previously stated, the applicable PSD regulations of the Arkansas SIP at the time of the White Bluff Unit 1 economizer replacement in 2006 only allowed for post project emissions to be based on representative actual annual emissions if the company maintained and submitted to ADEQ emissions information demonstrating that the economizer replacement did not result in an emissions increase. 40 C.F.R. § 52.21(b)(21)(v) (1997). However, Entergy only reported emissions for one year after the economizer replacement project. *See* February 25, 2008 Letter from Entergy to ADEQ at 1 (Ex. 28). Further, in its February 25, 2008 letter to ADEQ, Entergy acknowledged that actual emissions had increased above baseline, but Entergy simply stated that the increase to "factors unrelated to the project" such as "increased demand for power" without providing any demonstration to show that any actual emission increases were not related to the economizer replacement. *Id.*

Because Entergy did not properly follow the reporting requirements to allow for the use of an actual-to-representative actual annual emissions test for the economizer replacement project at White Bluff Unit 1, applicability to PSD for this project must be based on an analysis of actual-to-potential emissions. 40 C.F.R. § 52.21(b)(21)(v) and (iv) (1997). *United States v. Duke Energy Corp.*, 278 F. Supp. 2d 619, 647 n.25 (M.D.N.C. 2003) (holding that Duke Energy "'opted out' of the *WEPCO* calculus" by failing to satisfy the regulatory prerequisite of submitting emissions data for a five-year period following the physical change), *rev'd on other grounds Envtl. Def. v. Duke Energy Corp.*, 549 U.S. 561 (2007). Because applicability to PSD is to be determined prior to beginning actual construction on a project, the version of the PSD regulations in the Arkansas SIP at the time construction commenced on the White Bluff Unit 1 economizer replacement project in September of 2006 should continue to govern the

determination of whether the Unit 1 economizer project should have triggered applicability to PSD permitting requirements, despite the fact that the PSD regulations in the Arkansas SIP were revised in 2007.

(2) Entergy Improperly Excluded Emission Increases Projected to Occur After the Economizer Replacement Projects at White Bluff Units 1 and 2 as Due to Demand Growth.

In its PSD applicability analyses for the economizer replacements at both White Bluff Unit 1 and Unit 2, Entergy projected that significant increases in emissions of SO2 and NOx would occur at each unit in at least one of the five years after the economizer replacement compared with the company's determination of baseline emissions. Entergy's analysis also projected a significant emission increase in PM10, PM, and fluoride emissions at Unit 1 with the economizer replacement project. *See* July 31, 2006 Letter from Entergy to ADEQ regarding the economizer replacement at White Bluff Unit 1, Attachment at 1 (Ex. 22); August 8, 2007 Letter from Entergy to ADEQ regarding the economizer replacement at White Bluff Unit 2, Attachment at 1 (Ex. 23). However, Entergy appears to have not considered these significant emission increases as potentially triggering PSD because the company claimed all of the emission increases were due to electricity demand growth. *Id.* (In the cover letters to ADEQ for both the White Bluff Unit 1 and Unit 2 submittals, Entergy states "without this project, projected actual emissions will be higher simply due to normal economic activity including projected fuel prices and system electricity demand.")

Both versions of the Arkansas PSD regulations applicable to each economizer replacement project allow for a company to exclude, in calculating emissions increases from a project, "that portion of the unit's emissions following the [project]" that could have been

accommodated during the baseline period and that is unrelated to the particular change, including any increased utilization due to product demand growth. *See* 40 C.F.R. § 52.21(b)(33)(2) (1994); *see also* 40 C.F.R. § 52.21(b)(41)(ii)(c) (2007).

However, Entergy cannot simply claim all emissions increases are due to demand growth without demonstrating that those emission increases could have been accommodated during the baseline period ***and*** without showing that any emission increases are completely unrelated to the project. Entergy has failed to provide a reasoned demonstration to justify excluding its projected emission increases as due to demand growth and, as Sierra Club will detail below, no such demonstration can be made.

(a) White Bluff Units 1 and 2 Could Not Have Accommodated Entergy's Projected Increases in Each Unit's Capacity Factor During the Baseline Periods for the Unit 1 and Unit 2 Economizer Replacements.

As stated, one of the core requirements for excluding projected emission increases as due to demand growth is that the unit must have been capable of accommodating the projected increase in demand during the baseline period. However, the economizers were causing derates at both Units 1 and 2 due to ash pluggage, high ID fan amps, and similar related problems during the baseline periods for each unit's economizer projects. *See* FERC Form 1 Supplement, Annual Report of the Entergy-Arkansas, Inc. for 2003 to 2005 (Exs. 18A-18C). Thus, it is highly unlikely that White Bluff Unit 1 or Unit 2 were capable of accommodating Entergy's projected increases in capacity factors during each unit's respective baseline period. Neither ADEQ or Entergy has made any technical demonstration on this point to show otherwise.

Indeed, the available information pertinent to this issue reveals that Entergy's projected emission increases and increases in capacity utilization of White Bluff Unit 1 and Unit 2 ***are*** related to the installation of the new economizers at these units and therefore cannot be excluded in determining future projected actual emissions.

First, a review of the actual hourly megawatt ("MW") generation data for each White Bluff unit during the years before the economizer replacement compared to the two years after the economizer replacement make this clear. This data is publicly available in EPA's Clean Air Markets Database. A review of the gross MW generation data for White Bluff Unit 1 from 2003 through third quarter of 2009 (Ex. 32) reveals that the average of the highest 100 hours of gross megawatts generated increased significantly after the economizer was replaced in the fall of 2006 -- by 10-15 MW. Specifically, in the baseline years of 2003 and 2004, the average of the top 100 hours of electricity generated were 850.6 MW and 848.8 MW, respectively. In 2007 and 2008, after the Unit 1 economizer replacement, the average of the top 100 hours was 864 MW and 863.0 MW, respectively.

Similar increases were observed with the economizer replacement at White Bluff Unit 2. A review of the gross MW generation data for White Bluff Unit 2 from 2004 through 2010, Exs. 37A and 37B, shows that the average of the highest 100 hours of gross megawatts generated increased significantly after the economizer was replaced -- by 12-13 MW. During the 2004 and 2005 baseline period, the average of the top 100 hours of electricity generated at White Bluff Unit 2 was 872.9 MW and 873.6 MW, respectively. After the economizer was replaced in 2007, the average MW produced in the highest 100 hours was 885.4 MW in 2008, 887.1 MW in 2009, and 886.6 in 2010, which is approximately 14 MW higher than during the baseline.

Entergy claimed a 2.1% increase in the White Bluff Unit 1 capacity factor as compared to the capacity factor during the baseline period, but then appears to have claimed that all but approximately 0.1% of that increase in Unit 1's capacity factor was due to demand growth.[82] For Unit 2, Entergy claimed increased in capacity factor after the economizer replacement ranging from 1.5 to 5.4% as compared to average capacity factor during the baseline period, but then appears to have claimed that all but approximately 0.08% to 0.70% of that increase was due to demand growth.[83] However, based on a review of Entergy's annual reports to the Arkansas Public Service Commission and on the peak 100 hours of megawatts generated before and after the economizer replacements discussed above, it appears that both White Bluff Unit 1's and Unit 2's capacity factors were reduced in the years before the economizer replacements because pluggage in the economizers was acting as a bottleneck to operation of the units at full generating capacity. This means that Entergy could not exclude the emissions increases due to operating White Bluff Unit 1 and Unit 2 at increased capacity after the economizer replacements because the units were not capable of accommodating that capacity before the economizer replacements. Furthermore, the increases in capacity factor would clearly be related to the replacement of the economizers.

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[82] *See* July 31, 2006 Letter from Entergy's M. Bowles to ADEQ's T. Rheaume, Attachment at 4 (in Table "Delta (Change - Base Case)") (Ex. 22). It is also clear from a review of Entergy's "projected future actual with project" to the "projected future actual without project" tables that Entergy only assumed a 0.1% increase in capacity factor was due to the economizer replacement.

[83] *See* August 7, 2008 submittal from Entergy to ADEQ (Ex. 23), Attachment at 4 (in Table "Delta (Change - Base Case)") and Attachment at 2, in Table "Net Emissions Increase from Future Projected Actual Without Project."

Sierra Club further evaluated each unit's operations in the two years after replacement of the economizer compared to the two year baseline period to determine if the unit was capable of accommodating the increase in capacity factor during the baseline period. For Unit 1, Sierra Club compared the two years immediately after replacing the economizer (2007-2008) with Entergy's 2003-2004 baseline period. For Unit 2, Sierra Club compared the two years immediately after replacing the economizer (2008-2009) to Entergy's two year baseline period (2004-2005). Sierra Club's findings are provided in Tables 1 and 2 below. Although Unit 1 was operated 197 hours more in 2007-2008 compared to 2003-2004 at 200 MW or higher generating rates, the unit was operated many more hours at the maximum or near maximum generating rates ***after*** the economizer replacement as compared to how it was being operated during the baseline period. For example, in 2007-2008, Unit 1 operated 7,233 hours at or above 850 MW compared to 103 hours at or above 850 MW during the 2003-2004 baseline period. And the unit operated 896 hours at or above 860 MW during 2007-2008 when the unit operated zero hours at or above 860 MW during the baseline period.

Table 1: Evaluation of Data Reported by Entergy to EPA's Clean Air Markets Database for Baseline (2003-2004) and Two Years After Replacement of Economizer at White Bluff Unit 1 (2007-2008)[84]

[84] Note that this analysis excluded all heat input data that was identified in the Clean Air Markets Data as "substituted" to ensure that the generation data (for which substituted data is not indicated in the Clean Air Markets reports) reflects actual data, and the hours were normalized to reflect total hours of operation at or above 200 MW.

# of hours = > Stated Generating Rate (MW)	2003-2004	2007-2008	Difference after Economizer Replacement Compared to Before Economizer Replacement
200	15,595	15,690	95
300	15,484	15,642	158
400	14,155	14,712	558
500	13,649	14,356	708
550	13,346	14,103	756
600	12,966	13,808	842
650	12,475	13,379	904
700	11,753	12,805	1,051
750	10,421	12,003	1,581
800	7,288	10,674	3,386
810	6,040	10,283	4,243
820	4,458	9,789	5,332
830	2,862	8,965	6,103
840	1,233	7,979	6,747
850	103	7,233	7,130
860	0	896	896

Unlike White Bluff Unit 1, Unit 2 operated fewer hours during the first two years after replacement of the economizer, but the unit still operated many more hours at peak generating rates compared to during the baseline period. Specifically, Unit 2 was operated 1,837 hours less hours over 2008-2009 compared to 2004-2005. Yet, in 2008-2009, Unit 2 operated 5,230 hours at or above 870 MW compared to only 346 hours at or above 870 MW during the 2004-2005

baseline period. And the unit operated 3,658 hours at or above 880 MW during 2008-2009 when the unit operated 3 hours at or above 860 MW during the baseline period.

Table 2: Evaluation of Data in EPA's Clean Air Markets Database for Baseline (2004-2005) and Two Years After Replacement of Economizer at White Bluff Unit 2 (2008-2009)[85]

# of hours = > Stated Generating Rate (MW)	2004-2005	2008-2009	Difference after Economizer Replacement Compared to Before Economizer Replacement
200	15,662	14,644	-1,018
300	15,544	14,527	-1,017
400	13,220	13,928	708
500	12,271	13,489	1,218
550	11,894	13,193	1,299
600	11,343	12,804	1,461
650	10,534	12,318	1,784
700	9,624	11,654	2,030
750	8,509	10,914	2,405
800	6,596	9,933	3,337
810	5,917	9,670	3,753
820	5,008	9,396	4,388
830	3,713	9,016	5,303
840	2,824	8,533	5,709
850	2,309	7,630	5,321
860	1,298	6,199	4,901
865	926	5,778	4,852

[85] This analysis excluded all heat input data that was identified in CAMD as "substituted" to ensure that the generation data (for which substituted data is not indicated in the Clean Air Markets reports) reflects actual data, and the hours were normalized to reflect total hours of operation at or above 200 MW.

870	346	5,230	4,884
875	50	4,625	4,575
880	3	3,658	3,655
885	0	464	464

Thus, these tables clearly indicate that neither White Bluff Unit 1's nor Unit 2's increase in electricity demand at peak loads could not have been accommodated during the respective baseline period for each unit's economizer replacement. Given the problems that the unit was having with load limitations due to ash pluggage in the economizers, this is not surprising. If neither White Bluff unit could not have accommodated the demand growth projected by Entergy during the baseline period, then that projected growth in capacity factor of the unit cannot be excluded from Entergy's analysis of projected future actual emissions. *See* 40 C.F.R. § 52.21(b)(33)(ii) (1994); 40 C.F.R. § 52.21(b)(41)(ii)(c) (2007).

An analysis of the data reported by Entergy to the Arkansas Public Service Commission regarding the peak hourly electricity demand for "intrastate energy" (*i.e.*, not just White Bluff Unit 1 or 2, but statewide demand) for the 2004-2005 baseline years and the years 2008 and 2009, immediately after the economizer replacement at White Bluff Unit 2 provides further support for this conclusion.[86] Entergy reports the average maximum Arkansas load for each hour of the day. As Table 3 below shows, when one compares the average Arkansas maximum hourly loads for the two year baseline period used for the Unit 2 economizer replacement to the average Arkansas maximum hourly load for the two years after the economizer replacement at White Bluff Unit 2, there has been, on average, a drop in statewide peak electricity demand in the two

[86] This was determined from Entergy's FERC Form 1 Reports to the APSC, Data for Daily Peak Load Curves, for Years 2004, 2005, 2008, and 2009 (Exs. 24B, 24C, 24F, and 24G).

years immediately after the economizer replacement at Unit 2. And yet, during those same years, there has been an increase in hours that Unit 2 is operated at or near peak generating rates as compared to the unit's operation during the baseline period before the economizer replacement.

Table 3: Changes in Average Hourly Peak Load in Arkansas Before and After the White Bluff Unit 2 Economizer Replacement.[87]

Hour	2004-2005 Average of the Average Max Arkansas Load, MW	2008-2009 Average of the Average Max Arkansas Load, MW	Difference in Average Max Hourly Load in 2008-2009 Compared to 2004-2005, MW
1	4,037	3,764	-273
2	3,873	3,575	-298
3	3,725	3,443	-283
4	3,642	3,368	-274
5	3,610	3,340	-270
6	3,674	3,401	-273
7	3,813	3,541	-273
8	3,975	3,725	-250
9	4,213	3,972	-241
10	4,487	4,255	-233
11	4,742	4,439	-303
12	4,979	4,809	-171
13	5,184	5,030	-154
14	5,339	5,213	-126
15	5,425	5,296	-129
16	5,474	5,334	-141
17	5,500	5,330	-170
18	5,449	5,279	-170

[87] The Data for Table 3 is derived from Entergy's FERC Form 1 Reports to APSC, Data for Daily Peak Load Curves, for Years 2004, 2005, 2008, and 2009 (Exs. 24B, 24C, 224F, and 24G).

19	5,369	5,193	-176
20	5,226	5,063	-164
21	5,089	4,920	-169
22	4,983	4,775	-208
23	4,602	4,386	-217
24	4,277	4,055	-223

Given that in the two years following the Unit 2 economizer replacement there was no increase in demand in Arkansas, the significant increase in hours of operation of Unit 2 at or close to peak loads of 850 MW or greater strongly suggests that the replacement of the economizer at Unit 2 allowed for significantly increased hours of operation at or near the peak generating rate of Unit 2. This indicates that Entergy's projected increase in Unit 2's capacity factor after the replacement of the economizer could not be accommodated during the baseline period before the economizer replacement and is due to the replacement of the economizer.[88]

Based on the demonstration provided above, Entergy could not have credibly claimed that it could have accommodated its projected increases in each White Bluff unit's capacity factor during the respective baseline period for each unit's economizer replacement. And, in fact, Entergy never made such a claim. As previously stated, Entergy did not provide any demonstration that the projected increases in each unit's capacity factor could be accommodated during the baseline period for each unit's economizer replacement. The evidence provided in this petition and associated exhibits makes clear that Entergy cannot make such a demonstration, and, thus, there is no justification for Entergy's exclusion of projected emission increases due to

[88] Sierra Club was unable to perform a similar analysis for the two years before and after the economizer replacement at White Bluff Unit 1, because Entergy's FERC Form 1 Report for 2007 (the first year after the Unit 1 economizer replacement) did not include this data on intrastate electricity demand.

increases in each unit's capacity factor after the economizer replacements as due to demand growth.

(b) Entergy Has Not Adequately Shown that the Projected Increases in Emissions at White Bluff Units 1 and 2 Were Not Related to the Economizer Replacements and It Does Not Appear that Any Such Demonstration Could Be Made.

Even if Entergy could provide a demonstration that it could accommodate the projected increases in capacity factor of each unit during the respective baseline periods for the economizer replacements, which is highly unlikely, it would also be extraordinarily difficult for Entergy to demonstrate that any increase in demand growth was unrelated to the economizer projects since the company indicated that the economizer replacements would improve the heat rate of each unit. And making the units more efficient would result in the unit being dispatched more frequently.

Entergy indicated in its July 31, 2006 submittal to ADEQ that there would be a 59 Btu/kWhr decrease in heat rate of Unit 1 after the economizer replacement.[89] A review of the average annual heat rates reported in Entergy's FERC Form 1 Annual Reports shows that heat rate of Unit 1 decreased even more significantly. The annual average heat rate of White Bluff unit 1 was reported to be 10,491 Btu/kWh in 2003 and 11,981 Btu/kWh in 2004, while in 2007 the annual heat rate decreased to 10,383 Btu/kWh.[90] The decreased heat rate associated with the economizer replacement would very likely move Unit 1 up in the dispatch order. Similarly,

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[89] *See* July 31, 2006 Submittal, Attachment entitled "White Bluff Heat Rate Improvement Study" (Ex. 22).

[90] *See* 2003 Entergy FERC Form 1 Annual Report to the Arkansas Public Service Commission ("APSC") (Ex. 24A); 2004 Entergy FERC Form 1 Annual Report to the APSC (Ex. 24B); 2007 Entergy FERC Form 1 Annual Report to the APSC (Ex. 24E).

Entergy projected a 102 Btu/kWhr improvement in heat rate for the Unit 2 economizer replacement.[91] This projected efficiency improvement with the economizer replacement at Unit 2 would very likely increase demand for the unit, as with the Unit 1 economizer project.

Furthermore, because each unit was experiencing outages and derates related to the economizer, Entergy should have projected an increase in availability of the units with the replacement of the economizers because, after such replacements, the outages and derates would no longer be projected to occur.

Entergy did attempt to show that the projected increases in emissions were not related to the economizer replacements by projecting future actual emissions with the economizer replacements and without the economizer replacements.[92] However, there are numerous problems with the analyses. First, there is a lack of documentation as to what was accounted for in these analyses. The projections were based on ProSym runs, but neither the ProSym runs nor was the underlying data that went into those runs has ever been made publicly available. The following discussion addresses some of issues with the ProSym projections that Sierra Club has identified.

First, as previously stated, it is not clear that the post-economizer projections account for increased availability of the units after the economizer replacements. It is also not clear that the post-economizer projections account for the increased dispatch of the units with the improvement

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[91] *See* August 8, 2007 letter from Entergy to ADEQ regarding the economizer replacement at White Bluff Unit 2, Attachment at 4 (Ex. 23).

[92] *See* July 31, 2006 Submittal from Entergy to ADEQ, Attachment at 1-2 (Ex. 22); August 8, 2007 letter from Entergy to ADEQ regarding the economizer replacement at White Bluff Unit 2, Attachment at 1-2 (Ex. 23).

in heat rate due to the economizer replacements. While it appears Entergy assumed a 0.1% increase in projected capacity factor at Unit 1 and up to a 0.70% increase in projected capacity factor at Unit 2 as due to the economizer replacements at these units,[93] Entergy provides no indication of whether these projected increases are correlated with increased availability or increased dispatch.

Additionally, in projecting future heat input levels to for White Bluff Unit 1 after the economizer replacement, Entergy applied an adjustment to the heat input projected by ProSym "to resolve bias between CEMs heat input calculation and ProSym heat input numbers."[94] Given the discrepancies between the ProSym-generated heat input and the actual heat input data measured by CEMs that is used in each unit's baseline emissions calculation, which varied from -6.7% to 8.3% at Unit 1, it is not appropriate to use ProSym to project future heat input because it does not provide for an apples-to-apples comparison with baseline emissions. More details on this issue were provided in Sierra Club's January 10, 2012 letter to ADEQ at 18-19 (Ex. 68). *See also* July 31, 2006 Submittal to ADEQ, Attachment entitled "White Bluff Heat Rate Improvement Study" at Table with heading "Adjustment to resolve bias between CEMS heat input calculation and ProSym Heat Input numbers" (Ex. 22). Entergy did not apply a similar adjustment to the ProSym heat input numbers for the Unit 2 economizer replacement, which makes the Unit 1 adjustments all the more suspect.

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[93] *See* July 31, 2006 Submittal to ADEQ, Attachment entitled "White Bluff 1 Heat Rate Improvement Study" (Ex. 22); August 8, 2007 letter from Entergy to ADEQ, Attachment entitled "White Bluff 2 Heat Rate Improvement Study Due to Economizer and Toggle Joint R" (Ex. 23).

[94] *See* July 31, 2006 Submittal to ADEQ, Attachment entitled "White Bluff Heat Rate Improvement Study" (Ex. 22). It does not appear that any such adjustments were made to the projected heat input for the White Bluff Unit 2 economizer replacement from the ProSym run.

For the reasons discussed above, Entergy did not and, indeed, could not adequately show that its projected increases in the capacity factor for each White Bluff unit after the economizer replacements were completely unrelated to the projects. Because the company also did not and could not demonstrate that it was capable of accommodating its projected increase in capacity factors for each unit during the baseline period for each unit's economizer replacement, Entergy cannot exclude any projected emission increases as due to demand growth.

(3) Entergy's Projected Actual Emission Calculations Had Additional Flaws and Errors.

Not only did Entergy improperly and illegally exclude projected emission increases after the Unit 1 and Unit 2 economizer replacements as due to demand growth, but Entergy's projections of post-economizer actual emissions have other flaws and errors.

First, Entergy assumed the same emission rates would occur in future years as occurred during the baseline period for the Unit 1 and Unit 2 economizer replacement projects.[95] However, if Entergy replaced the economizers with a different design economizer that was less prone to plugging with ash, then it could allow different coals to be burned at White Bluff Units 1 and 2, including coals with higher sulfur or ash content. Furthermore, in 2006, the White Bluff permit was revised to allow the burning of bituminous coal in addition to subbituminous coal as well as coal with higher ash and sulfur content at both White Bluff units.[96] Given that White Bluff units

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[95] This was determined by dividing Entergy's projected amount of pollutants emitted by its projected heat input and comparing those emission rates to Entergy's average emission factors based on CEM data provided in the attachments to Entergy's July 31, 2006 and August 8, 2007 submittals to ADEQ.

[96] *See* description of Permit 0263-AOP-R4 in the Draft White Bluff Title V Renewal Permit (No. 0263-AOP-R7) at pdf 17 (Ex. 63); s*ee also* Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6), Section III, at pdf 18-19 (Ex. 30), which includes the permit history for Permit 0263-

were not authorized to burn these other coals during the respective baseline periods for the economizer replacements, the emission rates during the baseline period are not reflective of the coals that were planned to be burned in the future at White Bluff. The applicable definition of representative actual annual emissions required Entergy to consider "the company's own representations" and "the company's filings with the State or Federal regulatory authorities"in its determination of projected actual emissions. 40 C.F.R. § 52.21(b)(33)(i) (1994); 40 C.F.R. § 52.21(b)(41)(ii)(a) (2007). Thus, Entergy should have projected emissions based on emission factors reflective of the coal it would be able to burn in the future with the economizer replacements.

Indeed, a review of 2005 and 2010 stack tests for White Bluff Units 1 and 2 shows significant increases in total PM emission rates. Specifically, the total PM emission rate for Unit 1 was tested to be 0.016 lb/MMBtu in 2005, and in 2010 that increased to 0.049 lb/MMBtu.[97] Entergy assumed a total PM emission factor of 0.025 lb/MMBtu for Unit 1 in its calculations of both baseline actual emissions and projected actual emissions.[98] The total PM emission rate for Unit 2 was tested to be 0.012 lb/MMBtu in 2005 and in 2010, that increased to 0.057 lb/MMBtu.[99] The differences provides strong support for the argument that the PM emission

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AOP-R4 (Ex. 36).

[97] *See* September 26, 2005 E-mail from Entergy to ADEQ with 2005 White Bluff Stack Test Results at 2 (Ex. 33); April 2010 Source Emissions Survey of White Bluff Unit 1 at 4 (Ex. 34).

[98] This was determined by adding Entergy's PM emission factor, which only reflects filterable PM, to its emission factor for PM condensable provided in Entergy's July 31, 2006 Submittal from Entergy to ADEQ, Attachment at 1 (Ex. 22)..

[99] *See* September 26, 2005 E-mail from Entergy to ADEQ with 2005 White Bluff Stack Test Results at 2 (Ex. 33); April 2010 Source Emissions Survey of White Bluff Unit 2 at 5 (Ex. 35).

factors used by Entergy in its projected future actual emission analysis did not reflect the maximum annual rate at which Unit 1 or Unit 2 could be projected to emit PM.

In addition, Entergy used higher filterable PM10 and PM emission factors in its baseline emission calculations than it did in 4 out of 5 years of its post-project projections for the White Bluff Unit 2 economizer project. Specifically, Entergy used a PM10 emission factor of approximately 0.0076 lb/MMBtu in calculating baseline emissions and, while this factor was also used in the 2008 emission projections, a PM10 emission factor of approximately 0.0034 lb/MMBtu was used in the 2009-2012 emission projections.[100] Entergy also assumed a 0.026 lb/MMBtu emission rate for PM during the baseline period, but then projected emissions in 2009-2012 based on an emission factor of 0.014 lb/MMBtu.[101] There was no adequate justification for Entergy to assume that PM10 and PM emission rates would decrease at Unit 2 after the economizer replacement. Thus, clearly, Entergy underestimated future actual PM10 and PM emissions for Unit 2.

Further, none of these emission factors match with Entergy's stated average emission factor for particulate matter at White Bluff Unit 2.[102]

Second, although Entergy's 2006 submittal indicated only a 59 Btu/kWhr heat rate improvement with the economizer replacement at White Bluff Unit 1, Entergy's projected actual

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[100] This was determined by dividing the PM10 emissions identified for each year, converted to pounds, by the heat input identified for each year in Entergy's August 7, 2007 submittal to ADEQ, in the tables of "Actuals" and "Future Projected Actual with Project" (Ex. 23).

[101] This was determined by dividing the PM emissions identified for each year, converted to pounds, by the heat input identified for each year in Entergy's August 7, 2007 submittal to ADEQ, in the tables of "Actuals" and "Future Projected Actual with Project" (Ex. 23).

[102] *See* August 8, 2007 letter from Entergy to ADEQ, Attachment at 1 (Ex. 23).

emissions reflect a 124 Btu/kWhr improvement in heat rate.[103] Similarly, for White Bluff Unit 2, Entergy assumed a 102 Btu/kWhr decrease heat rate, yet Entergy's projected actual emissions reflect a 114 Btu/kWhr decrease.[104] It is also not clear why Entergy included the "Toggle Joint R" project with the economizer replacement project in projecting heat rate improvement.[105] It is questionable whether including the Toggle Joint R Project in determining heat rate improvement was even appropriate for these calculations. In any event, all of these discrepancies indicate that Entergy overstated the heat rate improvement with the economizer replacements in is emission projections and, consequently, the heat input and its projected actual emission calculations with the economizer project are inaccurate and substantially underestimate post change emissions.

Sierra Club raised these and other issues in its January 10, 2012 letter to ADEQ at 5-36 (Ex. 68). Due to these flaws, individually and collectively, Entergy's emission projections after replacement of the economizers at White Bluff Units 1 and 2 are deficient.

C. The Replacement of the Economizers at White Bluff Units 1 and 2 Should Have Been Projected to Result in a Significant Emission Increase and a Significant Net Emissions Increase of SO2 and NOx White Bluff Units 1 and 2, and of Other Regulated Pollutants at White Bluff Unit 1.

For all of the reasons discussed above, the economizer replacement projects at White Bluff Units 1 and 2 should have been projected to result in a significant emission increase and a

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[103] This was determined by calculating the heat rate during the baseline period in Btu/kWhr and calculating the heat rate during the five years after the economizer replacement, using the capacity factors provided by Entergy and assuming a unit gross generating capacity of 845 MW. *See* 1/10/12 Sierra Club's Additional Comments on the Draft Title V Renewal Permit for the Entergy Arkansas White Bluff Plant (No. 0263-AOP-R7) at 18 (Ex. 68) for more details.

[104] *Id. See* 1/10/12 Sierra Club's Additional Comments on the Draft Title V Renewal Permit for the Entergy Arkansas White Bluff Plant (No. 0263-AOP-R7) at 27-28 (Ex. 68) for more details.

[105] *See* August 8, 2007 submittal from Entergy to ADEQ, Attachment at 4 (Ex. 23).

significant net emissions increase of at least SO2 and NOx at both White Bluff units, if not other pollutants.

Specifically, for Unit 1, because the company did not report post-change emissions for the five years after the economizer replacement, post change emissions must be based on potential to emit rather than representative actual annual emissions. *See* 40 C.F.R. § 52.21(b)(21)(v) and (iv) (1997); *United States v. Duke Energy Corp.*, 278 F. Supp. 2d 619, 647 n.25 (M.D.N.C. 2003).

Table 4 below provides data for the actual to potential emission calculations, showing that significant emissions increases of SO2, NOx, PM, PM10, and other pollutants at Unit 1 are projected based on an actual-to-potential test for the economizer replacement. For the purpose of this analysis, Sierra Club did not attempt to recalculate baseline emissions, even though the emissions are inflated due to operation above the federally enforceable heat input capacity limitation of 8700 MMBtu/hr, as discussed above. Sierra Club also did not change the baseline emissions to the required two years prior to the economizer replacement (2004-2005). Had the baseline emissions been reduced to reflect compliance with the 8700 MMBtu/hr heat input capacity limit, the projected emission increases in Table 4 below would be even greater. Furthermore, had the baseline emissions been revised to the average of 2004-2005 emissions, the baseline emissions would have been lower.[106]

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[106] This is based on a review of 2004-2005 emissions data in the Clean Air Markets Database for White Bluff Unit 1.

Table 4. Evaluation of Emissions Increase at White Bluff Unit 1 Based on an Actual-to-Potential Emissions Test.[107]

	SO2, tpy	**NOx, tpy**	**Total PM10, tpy**	**Total PM, tpy**	**CO, tpy**	**Sulfuric Acid, tpy**	**Hydrogen Fluorides, tpy**
Baseline Emissions	21,586	10,026	533	1,090	885	6.33	53
Potential to Emit	45,727.2	26,674.2	3,127.4	3,127.4	14,221.9	55.93	344.93
Projected Increase in Emissions (Potential minus baseline)	24,141.4	16,648.2	2,594.4	2,037.4	13,336.9	49.6	291.93
Applicable PSD Significance Level	40	40	15	25	100	7	3

Clearly, based on an actual-to-potential emissions analysis, Entergy's economizer replacement at White Bluff Unit 1 should have been projected to result in a significant emissions increase of SO2, NOx, PM10, and several other regulated pollutants. Furthermore, given that there have been no creditable emission reductions at the White Bluff facility during the five years preceding the Unit 1 economizer replacement, the Unit 1 economizer project should have also

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[107] Baseline emissions are derived from Entergy's July 31, 2006 Submittal to ADEQ, Attachment at 1 (Ex. 22). Total PM and Total PM10 emissions based on Entergy's PM condensable emissions added to PM filterable and PM10 filterable emissions from Entergy's determination of baseline emissions. (Entergy's July 31, 2006 submittal indicates the PM and PM10 emission factors are based on Table 1.1-4 of AP42, which only addressed filterable PM and PM10 emission rates. Thus, to calculate total PM and PM10 emission rates, condensable emissions needed to be added to the filterable emissions). The potential to emit is derived from Section IV of the prior White Bluff Title V Permit (No. 0263-AOP-R6) (Ex. 2) and the PSD significance levels are derived from 40 C.F.R. § 52.21(b)(23)(i).

been projected to result in a significant net emissions increase of these pollutants. *See* 40 C.F.R. §52.21(b)(3) (1997). Consequently, based on an actual-to-potential test, the economizer replacement at White Bluff Unit 1 should be considered a major modification of these pollutants.

Even if it was appropriate to apply an actual-to-representative actual annual emissions test to the Unit 1 economizer replacement, Entergy should have projected a significant increase in SO2, NOx, PM10, PM, and fluoride emissions because it has not adequately justified the exclusion of its projected emission increases as due solely to demand growth as demonstrated in this petition. *See* 40 C.F.R. § 52.21(b)(33)(ii) (1994). Thus, Entergy should not be allowed to exclude any portion of its projected emission increases because it has not shown that its projected increases in Unit 1's capacity factor following the economizer replacement could have been accommodated during the baseline period, nor did Entergy adequately demonstrate that the projected increases were completely unrelated to the economizer replacement. As discussed in this petition, Sierra Club does not believe that any such demonstration could be made. As shown in Table 5 below, when no emissions are excluded from Entergy's future projected emissions, Entergy's emission projections show significant emission increases of several pollutants with the economizer replacement at White Bluff Unit 1.

Table 5. Evaluation of Emissions Increase at White Bluff Unit 1 Based on an Actual to Representative Actual Annual Emissions Test With No Emission Increases Excluded As Due Solely to Demand Growth.[108]

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[108] Baseline emissions are from Entergy's July 31, 2006 Submittal to ADEQ (Ex. 22), Attachment at 1. Total PM and Total PM10 emissions based on Entergy's PM condensable emissions added to PM filterable and PM10 filterable emissions from Entergy's determination of baseline emissions and for post project emissions. Representative actual annual emissions are

	SO2, tpy	**NOx, tpy**	**Total PM10, tpy**	**Total PM, tpy**	**Hydrogen Fluorides, tpy**
Baseline Emissions	21,586	10,026	533	1,090	53
Entergy's Future Projected Actual with Project, Average of 2007-2008 Projections	22,874	10,624	564	1,154.5	56.5
Projected Increase in Emissions (Projected actual minus baseline)	1,288	598	31	64.5	3.5
Applicable PSD Significance Level	40	40	15	25	3

Similarly, Entergy should have projected a significant increase in at least SO2 and NOx with the economizer replacement at White Bluff Unit 2, because it has not adequately justified the exclusion of its projected emission increases as due solely to demand growth as demonstrated in this petition. *See* 40 C.F.R. § 52.21(b)(41)(ii)(c) (2007). Thus, Entergy should not be allowed to exclude any portion of its projected emission increases because it has not shown that its projected increases in Unit 2's capacity factor following the economizer replacement could have been accommodated during the baseline period, nor did Entergy adequately demonstrate that the

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based on the average of the two years after the economizer replacement (per 40 C.F.R. § 52.21(b)(33)(ii)), and Entergy's "Future Projected Actual with Project" emission projections. PSD significance levels are derived from 40 C.F.R. § 52.21(b)(23)(i).

projected increases were completely unrelated to the economizer replacement. In the table below, Sierra Club has provided Entergy's determination of baseline emissions and Entergy's year of highest emission projections after replacement of the economizer at White Bluff Unit 2, since an emission increase will be considered significant if one year of the five years post change has a significant emission increase compared to baseline emissions. *See* 40 C.F.R. §52.21(b)(41)(i) (2007). As shown in Table 6 below, when no emissions are excluded as due to solely to demand growth, Entergy's emission projections show significant emission increases of SO2 and NOx with the economizer replacement at White Bluff Unit 2.

Table 6. Evaluation of Emissions Increase at White Bluff Unit 2 Based on an Actual to Projected Actual Emissions Test With No Emission Increases Excluded As Due Solely to Demand Growth.[109]

	SO2, tpy	**NOx, tpy**
Baseline Emissions	20,238	8,503
Entergy's Future Projected Actual with Project in 2012	20,948	8,801
Projected Increase in Emissions (Projected actual minus baseline)	710	298
Applicable PSD Significance Level	40	40

As Sierra Club has discussed in this petition, Entergy's projected emission increases shown in Tables 5 and 6 above are low for several reasons. First, Sierra Club did not attempt to recalculate baseline emissions even though the emissions are inflated due to operation above the

[109] Baseline emissions are derived from Entergy's August 8, 2007 Submittal to ADEQ, Attachment at 1 (Ex. 23). Future projected actual with project is based on the year of highest projected capacity utilization of White Bluff Unit 2 - 2012. PSD significance levels are derived from 40 C.F.R. § 52.21(b)(23)(i).

federally enforceable heat input capacity limitation of 8700 MMBtu/hr, as discussed above. Had the baseline emissions been reduced to reflect compliance with the 8700 MMBtu/hr heat input capacity limit, the projected emission increases in the tables above would be even greater.

Sierra Club also did not attempt to address any of the other flaws in Entergy's post-project emissions projections. As previously discussed, those flaws include (but are not limited to) that Entergy did not use different post-change emission factors reflecting the worst case coal the units are now authorized to burn and/or that the new economizers would provide for using, the fact that Entergy appears to have assumed a greater heat rate improvement in its annual heat input projections than it claimed it would achieved with the economizer replacements, and that the PM and PM10 emission factors used for Entergy's post-change emission projections at White Bluff Unit 2 are much lower than the emission factors used in the calculation of baseline emissions for PM and PM10.

Furthermore, it is highly questionable that expected improvement in heat rate should be evaluated in determining whether there will a significant emission increase as a result of the economizer replacements. Taking into account emission decreases along with emission increases in the first part of PSD applicability of whether there will be a significant emission increase, *i.e.*, the "Step 1 analysis," is known as "project netting." EPA has made clear such project netting is not allowed under the current PSD regulations.[110] When EPA adopted the Step 1 requirements into the PSD regulations in 2002, EPA stated that it was simply codifying longstanding policy, which provided that before a source has to evaluate net emissions increase for a modification,

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[110] This is discussed in great detail in EPA's March 30, 2010 letter to HOVENSA, L.L.C (Ex. 38).

that modification must first be projected to result in a significant emission increase (not including any emission decreases).[111]

Even without these other deficiencies addressed, it is clear that based on an actual-to-future actual emissions test with no portion of the projected emissions increases excluded as due to demand growth, Entergy's economizer replacements at White Bluff Unit 1 and Unit 2 are projected to result in a significant emissions increase of SO2 and NOx at each unit, as well as PM10, PM, and fluorides at Unit 1. And, if applicability to PSD is based on an actual-to-potential emissions analysis, as Sierra Club contends is required at White Bluff Unit 1, the economizer replacement at this unit is projected to result in a significant emission increase of several other regulated pollutants. *See* Table 4 above. Given that there have been no creditable emission reductions at the White Bluff facility during the five years preceding the Unit 1 or the Unite 2 economizer replacements, each of the economizer projects should have also been projected to result in a significant net emissions increase of SO2 and NOx at each White Bluff unit and of, at least, PM, PM10, and fluorides for White Bluff Unit 1. *See* 40 C.F.R. §52.21(b)(3). Consequently, based on an actual-to-future actual emissions test, the economizer replacements at White Bluff Unit 1 and at Unit 2 should be considered as major modifications for these pollutants.

In summary, EPA must object to the White Bluff Title V permit because it omits the PSD requirements applicable to the replacement of the economizers that occurred in 2006 at White Bluff Unit 1 and in 2007 at White Bluff Unit 2. Those requirements include the imposition of

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[111] *See* 67 Fed.Reg. 80190 (December 31, 2002); *see also* October 1990 New Source Review Workshop Manual at A.45.

BACT emission limits for SO2 and NOx at both White Bluff Units 1 and 2, and for at least PM/PM10 and fluorides at Unit 1, and could also include other requirements as necessary to assure compliance with the NAAQS, PSD increments, and/or to protect Class I air quality related values. *See* 40 C.F.R. §§ 52.21(k), (o), and (p), incorporated by reference into APCEC Reg. 19.904(A), approved as part of the SIP by EPA at 40 C.F.R. § 52.170(c).[112]

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[112] In its August 2012 Final Response to Comments at 10, ADEQ asserts that Sierra Club's comments challenging whether the prior economizer replacements triggered NSR/PSD and require the imposition of BACT limits are untimely and, consequently, ineffective. Specifically, ADEQ position is that because (1) the subject economizer replacement projects were reported by letter to ADEQ and approved, as far as the record shows, by inaction and silence on ADEQ's part and (2) subsequently two Title V permits were issued without the submission of any public comments challenging the economizer replacements from Sierra Club or any other member of the public, then (3) the issues regarding whether PSD was triggered by these economizer replacements can no longer be raised since it was not challenged in those preceding permits. ADEQ is wrong on this point for several reasons.

First, the economizer replacements were not reported publicly or subject to public notice so only an exceedingly diligent and informed commenter would even have an inkling that there had ever been such significant economizer issues. Without adequate notice, there can be no legitimate argument that an opportunity to comment and challenge these actions has been waived or otherwise lost.

Second, the two subsequent permits which ADEQ was referring to were White Bluff Title V Permit (No. 0263-AOP-R5) and White Bluff Title V Permit (No. 0263-AOP-R6)), which, significantly, were not Title V renewal permits but rather were modification permits. "EPA interprets its Title V regulations at 40 C.F.R. part 70 to require different opportunities for citizens to petition on initial permit issuance, permit modifications, and permit renewals." *In the Matter of Wisconsin Public Service Corporation - Weston Generating Station*, Permit No. 73700902 & P02, Petition No. V-2006-4, Order at 5 (Ex. 89). EPA has clearly stated that for modification permits such as these, the scope of public comment is narrowly limited "to issues directly related to [the] modifications" in question. *Id.* However, where a Title V renewal permit is concerned, comments may address any aspect of the permit whatsoever. "At the time the permitting authority issues the source its Title V permit, the public is provided an opportunity to review, comment on, and object to any aspect of that permit. Sources are also required to ***renew the permit*** at least every five years, and ***that process also provides the public with an opportunity to review, comment on, and object to all aspects of the permit***." *Id.* at 5-6 (citing 40 C.F.R. § 70.7(c) (emphasis added)). Accordingly, this is the first time that Sierra Club could have properly commented on the question of whether the economizer replacement triggered PSD.

Issue #4: The Administrator Must Object to the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) Because It Fails to Identify and Include All Applicable PSD Requirements Derived and Imposed as a Consequence the Previously Permitted Changes in Coal Combusted at White Bluff, Switching From Subbituminous to Bituminous Coal and Coal With a Higher Sulfur and Ash Content, Which Triggered PSD Review.

In 2006, ADEQ issued a permit modification (Permit 0263-AOP-R4) for the White Bluff facility that allowed several changes regarding the coal burned at White Bluff. Among other things, this permit allowed a change from the prior requirement that only subbituminous coal from northeastern Wyoming could be burned at the White Bluff boilers, and authorized the burning of bituminous coal as well as subbituminous coal from other locations.[113] The permit also increased the coal sulfur and ash contents, and allowed for coal to be received via barge.[114]

Permit 0263-AOP-R4 authorized significant increases in PM and PM10 emissions. The permit authorized 24.9 tpy of new PM emissions for coal barging and transfer.[115] The permit also included significant increases in the allowable emissions of the White Bluff Unit 1 and 2

Third, as EPA clarified in the *Weston* petition response, in any permit renewal, any aspects of a permit are appropriate to address, including the all the NSR/PSD questions raised by Sierra Club here, regardless of whether theoretically some member of the public could have raised them earlier in some other permitting context. Since Sierra Club properly raised these issues with reasonable specificity in comments submitted to ADEQ in this permit renewal process and complied with all pertinent state requirements, *see generally* Ark. Code Ann. § 8-4-205(b)(2); Ark. Code Ann. § 8-4-203(g), and APCEC Reg. No. 8.214 (ADEQ claims these provisions bar Sierra Club from raising this and similar issues at this time but these provisions do not address when issues can be addressed in the Title V renewal process or in the EPA petition process; rather, they set forth the standard state administrative requirement that one generally must have commented to the state on an issue in order to have standing in Arkansas to appeal to the state commission or to raise an issue in an administrative hearing), Sierra Club is free to file this petition and EPA is unquestionably free to substantively address them in response.

[113] *See* Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6), Section III, at pdf 18-19 (Ex. 30), which includes the permit history for Permit 0263-AOP-R4 (Ex. 36).

[114] *Id.*

[115] *See* White Bluff Permit (No. 0263-AOP-R4) at 43, Table 19 (Ex. 36).

boilers (SN-01 and SN-02). According to ADEQ's Permit History in Section III of the White Bluff permit, Permit 0263-AOP-R4 "[s]et the PM10 emission rate limits equal to the PM emission rate limits for SN-01 [White Bluff Unit 1] and SN-02 [White Bluff Unit 2]."[116] However, that statement is not quite correct, because a comparison of the emission limits in the prior Title V permit for White Bluff, Permit 0263-AOP-R3 (Ex. 29), to the emission limits for the White Bluff boilers in Permit 0263-AOP-R4 shows that ADEQ increased both the PM and PM10 emission limits of the White Bluff permit by very significant amounts. Table 7 below shows the PM and PM10 limits applicable to the White Bluff Unit 1 and 2 boilers were increased well in excess of the PSD significance levels of 25 tpy for PM and 15 tpy for PM10.

Table 7: Changes in PM and PM10 Emission Limits Allowed at Each Unit at White Bluff

	Permit 0263-AOP-R3 Limits for SN-01&SN-02		**Permit 0263-AOP-R4 Limits for SN-01&SN-02**		**Increase in Allowable Emissions at SN-01&SN-02**	
PM	453.0 lb/hr	1,984.2 tpy	714.0 lb/hr	3,127.4 tpy	261 lb/hr	1,143.2 tpy
PM10	140.0 lb/hr	613.1 tpy	714.0 lb/hr	3,127.4 tpy	574 lb/hr	2,514.3 tpy

Thus, overall, Permit 0263-AOP-R4 allowed a 2,286.4 tpy increase in PM and a 5,028.6 tpy increase in PM10 from the White Bluff boilers.

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[116] *See* Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6), Section III, at pdf 18-19 (Ex. 30), which includes the permit history for Permit 0263-AOP-R4 (Ex. 36).

ADEQ made these very significant changes to the coal usage and PM/PM10 emission rates without subjecting the White Bluff units to PSD review for the significant increase in PM and PM10 emissions. According to ADEQ's Statement of Basis for Permit 0263-AOP-R4:

> The total permitted emission rate increases due to this permitting action include 2,311.3 tons per year (tpy) PM and 5,034.8 tpy PM10. These increases do not require PSD review because there is no physical modification to the boilers (SN-01 and SN-02) and the coal barging and transfer (SN-19) as been permitted below the PSD trigger.

Statement of Basis for Permit 0263-AOP-R4 at 2 (Ex. 39).

ADEQ's findings are based on an improper interpretation of the PSD regulations and are simply wrong. There is no question but that these permit changes should have been permitted as major modifications of PM and PM10, requiring, among other things, the application of BACT for PM and PM10 to the White Bluff Units 1 and 2.[117] Sierra Club raised these issues in great detail in its January 10, 2012 letter to ADEQ at 36-49 (Ex. 68). Based on the information in Sierra Club's comment letter to ADEQ as detailed below, Sierra Club petitions EPA to object to the Final White Bluff Title V permit because it fails to include the applicable PSD requirements including BACT emission limits applicable to the permit changes associated with the change in the types of coal that could be burned at White Bluff Unit 1 and Unit 2.

A. Applicable PSD Regulations at the Time of Issuance of Permit 0263-AOP-R4.

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[117] Sierra Club raised this issue (and all the related issues discussed below) in its January 10, 2012 comment letter to ADEQ on the draft White Bluff Title V renewal permit. *See* 1/10/12 Sierra Club's Additional Comments on the Draft Title V Renewal Permit for the Entergy Arkansas White Bluff Plant (No. 0263-AOP-R7) at 36-49 (Ex. 68).

Permit 0263-AOP-R4 was issued April 26, 2006.[118] Arkansas has incorporated by reference the Federal PSD regulations at 40 C.F.R. § 52.21 into state regulations. Although, at the time of issuance of Permit 0263-AOP-R4, the state had adopted EPA's 2002 revisions to its PSD regulations as part of Arkansas Reg. 19.904, EPA had not yet approved those revised regulations as part of the Arkansas SIP. In fact, EPA did not approve Arkansas' current PSD regulations which reflect EPA's 2002 PSD rule revisions as part of the Arkansas SIP until April 12, 2007 (72 Fed. Reg. 18394 (April 12, 2007)).

Although there are some significant differences in the two versions of the Arkansas SIP's PSD rules, there are two fundamental components to determining applicability of these modifications at the White Bluff units to PSD. To constitute a "major modification" which triggers PSD applicability: (1) there must be a physical change or change in the method of operation and (2) there must be a significant emission increase. More specifically, under the prior version of the Arkansas SIP's Reg. 19.901, there must be a "significant net emissions increase," APCEC Reg. 19.904; 40 C.F.R. § 52.21(b)(2)(i) (1994), and under the most recent version of the Arkansas SIP, there must be both a "significant emissions increase" and a "significant net emission increase." APCEC Reg. 19.904; 40 C.F.R. § 52.21(a)(2)(iv)(a) (2007).

There is no question that a change in coal type at the White Bluff boilers constitutes a change in the method of operation. Further, an increase in the allowable PM and PM10 emissions of White Bluff Units 1 and 2 constitutes a change in the method of operation.

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[118] *Id.*

Specifically, the definition of "major modification" is defined as a "physical change or change in the method of operation" that would result in a significant net emissions increase of a regulated NSR pollutant. 40 C.F.R. § 52.21(b)(2)(i) (1994). The definition explains what is not a physical change or change in the method of operation as follows:

> A physical change or change in the method of operation shall not include:
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> (a) Routine maintenance, repair and replacement.
>
> (b) Use of an alternative fuel or raw material by reason of an order under sections 2 (a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plant pursuant to the Federal Power Act;
>
> (c) Use of an alternative fuel by reason of an order or rule under section 125 of the Act;
>
> (d) Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;
>
> (e) Use of an alternative fuel or raw material by a stationary source which:
>
> (1) 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; or
>
> (2) The source is approved to use under any permit issued under 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.166;
>
> (f) An increase in the hours of operation or in the production rate, 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.
>
> (g) Any change in ownership at a stationary source. . . .

40 C.F.R. § 52.21(b)(2)(i) (1994). The above regulatory language is also identical in the 2002 regulations that were approved as part of the Arkansas SIP in 2007.

The above language makes clear that PSD is not only triggered by physical changes that cause significant net emission increases; PSD can also be triggered by changes in the method of operation that cause significant net emissions increases.

To determine whether a physical change or change in the method of operation would result in a major modification, one must determine the net emissions increase expected to result from the physical change or change in the method of operation. The PSD rules applicable under the Arkansas SIP at the time of Permit 0263-AOP-R4 allow PSD applicability to be based on a comparison of actual emissions to representative actual annual emissions for the modified unit(s) if the company reports post-project emissions for a period of at least five years after the change at the unit. Specifically, 40 C.F.R. § 52.21(b)(21)(v) (1994) allows for the use of representative actual annual emissions post-change "provided that the source owner or operator maintains and submits to the Administrator on an annual basis for a period of 5 years from the date the unit resumes regular operation, information demonstrating that the physical and operational change did not result in an emissions increase." If such reporting is not to be provided for 5 years following the change, then applicability to PSD is based on a comparison of actual emissions to potential to emit after the change. *See* 40 C.F.R. § 52.21(b)(21)(iv) (1994). *See also United States v. Duke Energy Corp.*, 278 F. Supp. 2d 619, 647 n.25 (M.D.N.C. 2003). Clearly, no such reporting was done because ADEQ incorrectly found this modification was not subject to PSD due to the fact that there was no physical change to the White Bluff boilers. Thus, applicability must be based on a determination of actual emissions before the change to potential emissions after the change. However, even if the emission increases were evaluated based on an actual to

representative actual annual emission basis, a significant increase in PM, PM10, and SO2 emissions would be projected, as will be discussed below.

B. The Change in Coal Burned Authorized in Permit 0263-AOP-R4 Constituted a Change in the Method of Operation.

There is no question that a fuel change, including fuel switching or blending, is a change in the method of operation. EPA previously made this very clear in its October 4, 2006 letter to ADEQ, which responded to a June 20, 2006 letter from Entergy requesting an applicability determination for a proposal to burn a lignite blend at both White Bluff and Independence Stations.[119] A change from burning subbituminous coal from northeastern Wyoming to subbituminous and bituminous coal as authorized by Permit 0263-AOP-R4 is clearly a change in the method of operation.

Although fuel switches can, in some cases, be considered exempt from being treated as a change in the method of operation under the PSD regulations, none of those circumstances apply to the fuel changes at White Bluff. As stated above, the definition of major modification provides that a physical change or change in the method of operation does not include the use of an alternative fuel or raw material "which the source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit

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[119] *See* October 4, 2006 letter from EPA to ADEQ at 3 and n. 1 (Ex. 40). This October 2006 letter from EPA is much more recent and far better reasoned that the ancient 1980 Reich memo relied on by ADEQ, August 2012 ADEQ Final Response to Comments at Attachment 1 (Ex. 76) (June 18, 1980 memo from Edward E. Reich, Director, Division of Stationary Source Enforcement to Allyn Davis, Director, Air & Hazardous Materials Division, Region VI) and should be viewed as overriding any contrary indications in the Reich letter.

condition. . . ." 40 C.F.R. § 52.21(b)(2)(iii)(e)(1) (1994). For two primary reasons, this alternative fuel exemption was not applicable to coal switch at issue here.

First, the White Bluff units were not capable of accommodating any fuel before January 6, 1975, because the units were not yet constructed. *See, e.g.*, January 2009 Application for Permit to Construct Entergy White Bluff Units 1 & 2 Air Pollution Control Project at 15 (Ex. 64). Second, the applicable permits issued by ADEQ always prohibited the burning of anything but low sulfur subbituminous coal from the time the White Bluff plant was originally permitted through 2006 when Permit 0263-AOP-R4 was issued.[120]

Because, prior to January 6, 1975, the White Bluff units could not have accommodated the different types of coals allowed via the 2006 permit revision, the alternative fuel exemption of 40 C.F.R. § 52.21(b)(2)(iii)(e)(1) was not applicable to that 2006 action allowing the White Bluff units to burn bituminous coal and coal with higher sulfur and ash content.[121] Consequently,

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[120] *See* November 22, 1974 Air Permit (Ex. 41), which required White Bluff to burn low sulfur coal. *See also* the document entitled "Sulphur Dioxide Emissions Control at the White Bluff Steam Electric Station, December 1978 (Ex. 42) at 5 and in Appendix D, which states that the coal for White Bluff will be from the Jacobs Ranch Mine in Campbell County near Gillette, Wyoming (*i.e.*, subbituminous coal from northeastern Wyoming). *See also* 4/9/91 Permit for White Bluff (Ex. 43), which states in the Summary that both units burn sub-bituminous coal; the original Title V Permit 0263-AOP-R0 for White Bluff issued April 24, 1998 (Ex. 44) at 3 and 10, which states that the White Bluff units burn subbituminous coal from northeastern Wyoming; and Permit 0263-AOP-R3 at 6 and 18 (Ex. 29), which continued to require the burning of subbituminous coal from northeastern Wyoming.

[121] Arkansas also has a definition of "modification" in Chapter 2 of APCEC Reg. 19, which exempts use of alternative fuels "as long as it does not violate applicable air permit conditions." This definition is not applicable to the state and federal PSD program but, regardless, the coal change and corresponding increases in sulfur content, ash content, and PM/PM10 emission rates at White Bluff would also be considered a "modification" under definition of modification in Reg. 19, Chapter 2. Because prior White Bluff permits limited the coal burned to subbituminous coal from northeastern Wyoming, and included lower limits on PM/PM10 emissions, the change

the change in coal permitted by ADEQ in 2006 was a change in the method of operation that triggered PSD review. The conclusion drawn by ADEQ that the permitted coal switch was exempt from PSD review because, according to ADEQ, there was "no physical change to the boilers,"[122] was clearly erroneous and contrary to law.[123]

C. There Was Also At Least One and Potentially More Physical Changes Made at the White Bluff Facility to Accommodate Burning Different Coals.

1. The Addition of Coal Barging Operations Was a Physical Change Made to White Bluff to Facilitate the Burning of Different Coals.

While the fuel changes alone constitute a change in the method of operation that should have been reviewed for PSD applicability by ADEQ, but was not, there was also at least one physical change made at White Bluff and possibly others made to accommodate the burning of different coals. One physical change that was made at the White Bluff facility that is clearly related to the change in fuels is the coal barging operations that were also authorized in Permit

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in fuels at White Bluff would have violated applicable air permit conditions. This is why ADEQ had to revise the White Bluff Title V permit to allow for use of bituminous coal and higher sulfur and ash coal.

[122] As stated by ADEQ in its Statement of Basis for Permit 0263-AOP-R4 at 2 (Ex. 39).

[123] In its August 2012 Final Response to Comments at 12-13, ADEQ asserts that Sierra Club's comments addressing the fuel switch issue have been waived because Sierra Club failed to submit comments and challenge the fuel switch in prior permitting contexts. As discussed previously, this is a permit renewal process wherein Sierra Club is entitled to address any aspect of the permit that it believes is objectionable. *See generally In the Matter of Wisconsin Public Service Corporation - Weston Generating Station*, Permit No. 73700902 & P02, Petition No. V-2006-4, Order at 5-7 (Ex. 89). Since Sierra Club raised the fuel switch-related issues with reasonable specificity in its comments submitted to ADEQ in the course of this permit renewal process, Sierra Club has not waived any rights to address these issues, either through comments to ADEQ or through this petition to EPA.

0263-AOP-R4, which provided the White Bluff facility with the ability to receive coal other than by railroad from the Powder River Basin.[124]

2. The Increases in Permitted Circulating Water Flow of the White Bluff Units 1 and 2 Cooling Towers Was a Physical Change Made to the White Bluff Facility That May Be Related to the Burning of Different Coals At White Bluff.

It is possible that physical changes were also made to the White Bluff plant that were, at least in part, related to the change in fuels. One change that was permitted at the same time as the coal switch (in Permit 0263-AOP-R4) was the aforementioned increase in the permitted circulating water flow rate of the cooling towers for White Bluff Units 1 and 2 from 20,700 kgal/hr per tower to 22,125 kgal/hr per tower.[125] Interestingly, the permitted circulating water flow was changed in the previously applicable White Bluff permit (Permit 0263-AOP-R3, issued in April 2005) from 19,560 kgal/hr to 20,700 kgal/hr.[126] Entergy's reasoning for the increase from 19,560 kgal/hr to 20,700 kgal/hr was that "the annual flow test results have consistently

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[124] In its August 2012 Final Response to Comments at 13, ADEQ asserts that Sierra Club's comments addressing the coal barging issue have been waived because Sierra Club failed to submit comments addressing this issue in regards to White Bluff Title V Permit (No. 0263-AOP-R4). As discussed previously, this is a permit renewal process wherein Sierra Club is entitled to address any aspect of the permit that it believes is objectionable. *See generally In the Matter of Wisconsin Public Service Corporation - Weston Generating Station*, Permit No. 73700902 & P02, Petition No. V-2006-4, Order at 5-7 (Ex. 89). Since Sierra Club raised these issues with reasonable specificity in its comments submitted to ADEQ in the course of this permit renewal process, Sierra Club has not waived any rights to address these issues, either through comments to ADEQ or through this petition to EPA.

[125] *See* Permit 0263-AOP-R3, Condition 80, at 43 (Ex. 29) and Permit 0263-AOP-R4, Condition 82, at 42 (Ex. 36).

[126] *See* Permit 0263-AOP-R2 at 29 (Condition 58 which limited the circulating water flow of the White Bluff cooling towers to 19,560 kgal/hr) (Ex. 55); *see also* Permit 0263-AOP-R3 at 43 (Condition 80, which increased the allowable circulating water flow of the White Bluff cooling towers to 20,700 kga;/hr per tower) (Ex. 29).

been within 5%" of the 19,560 kgal/hr limit and that Entergy "would feel more comfortable with the increased limit to allow for deviations in actual pump performance."[127] Entergy replaced the circulating water pumps for the White Bluff Units 1 and 2 cooling towers and submitted PSD applicability reviews for the increased emissions associated with the cooling tower flow increase.[128] However, shortly after the circulating water pump upgrades, Entergy informed ADEQ that the project "resulted in an increased circulating water flow rate greater than the expected calculated increase," and revised permit application forms were submitted indicating a maximum operating rate of the Unit 1 and Unit 2 cooling towers of 22,125 Kgal/hr.[129]

These changes to the circulating water flow of the White Bluff cooling towers were likely related to the change in coal burned at White Bluff Units 1 and 2. At the very least, it appears likely that these changes were all permitted at the same time for a reason. One very plausible reason is that Entergy's change from burning subbituminous coal from northeastern Wyoming to any subbituminous or bituminous coal, even if blended with subbituminous coal from the Powder River Basin, could very well have increased the steam generating capacity of the White Bluff boilers which would, in turn, require more cooling tower flow to dissipate the increased heat. Specifically, the boilers were, at that time, permitted to burn 525 tons of coal per hour. Subbituminous coal from northeastern Wyoming has a much lower heat value than bituminous coal. And it also typically has a lower heat value than other western subbituminous coal such as

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[127] *See* March 14, 2005 letter from Entergy to ADEQ at 1 (Ex. 46).

[128] *See* March 23, 2005 Submittal from Entergy to ADEQ regarding the increased flow rate for the White Bluff cooling towers (Ex. 45).

[129] *See* July 5, 2005 letter from Entergy to ADEQ at 1 and attached Emission Rate Table (at pdf 7-8) (Ex. 47) .

ColoWyo coal. The heat value of the Powder River Basin coal historically used at White Bluff is approximately 8,400 Btu/lb, whereas the heat value of ColoWyo coal (which is one of the coals that has been utilized at White Bluff since first requesting to burn different coals in 2005) is approximately 10,600 Btu/lb.[130] Entergy has indicated that it has burned Columbian coal at the White Bluff units, which has a heat value of 11,400 Btu/lb.[131]

With its request to burn different coal, Entergy did not indicate any expected decrease in the maximum coal throughput per hour of (at that time) 525 tons per hour per White Bluff unit.[132] Thus, if Entergy burns the same amount of coal in terms of tonnage fed to the boilers per hour, but that coal has a higher heat value, then the heat input to the boilers will increase. And if the heat input to the boilers increases, that will in turn increase the steam production which in turn will require an increase in cooling tower capacity. Accordingly, it appears very likely that the increase in permitted water flow capacity of the White Bluff Units 1 and 2 cooling towers is related to the request to burn different coals at White Bluff.[133]

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[130] *See* 2000 Directory of Power Plants Burning Wyoming Coal, Wyoming Geological Survey, at PP-4 (Ex. 48). *See also* July 18, 2005 Letter from ADEQ to Entergy authorizing the burning of ColoWyo coal (Ex. 49).

[131] *See* August 10, 2005 e-mail from George Johnson (Entergy) to Thomas Rheaume (ADEQ) (Ex. 50).

[132] *See* February 21, 2006 email from George Johnson (Entergy) to Ann Sudmeyer (ADEQ) (Emission Rate Tables) (Ex. 51). Note that Entergy continues to identified the heat value of the coal burned at White Bluff as approximately 8300 Btu/lb, which is clearly not correct for all coals to be burned at White Bluff.

[133] In its August 2012 Final Response to Comments at 12-13, ADEQ asserts that Sierra Club's comments addressing the circulating water flow rate increases pertaining to the fuel switch issue have been waived because Sierra Club failed to submit comments and address this issue in prior permitting contexts. As discussed previously, this is a permit renewal process where Sierra Club is entitled to address any aspect of the permit that it believes is objectionable. *See generally In the Matter of Wisconsin Public Service Corporation - Weston Generating Station*, Permit No.

3. The Economizer Replacements at White Bluff Units 1 and 2 May Be Related to the Burning of Different Coals at White Bluff.

Another physical change made to the White Bluff facility that may be related to Entergy's permit change to burn different coals is the economizer replacements at White Bluff Units 1 and 2. As discussed above, Entergy replaced the White Bluff Unit 1 economizer in 2006 and the White Bluff Unit 2 economizer in 2007.[134] As previously stated, it is very likely that Entergy replaced the economizers with economizers of a different design, one that is less likely to plug with ash. *See discussion supra.* In Permit 0263-AOP-R4, Entergy was authorized to burn coals of higher ash content.[135] Thus, it is likely that the economizer replacements at the White Bluff boilers reflect physical changes to the boilers that are associated with, or are even necessary to accommodate, the burning of higher ash coals.

4. Summary

While there is no question that the burning of a different coal other than subbituminous coal from northeastern Wyoming at White Bluff Units 1 and 2 is a change in the method of operation at the White Bluff facility that must be evaluated for PSD applicability, there was also at least one physical change at the White Bluff plant that was necessary to accommodate the

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73700902 & P02, Petition No. V-2006-4, Order at 5-7 (Ex. 89). Since Sierra Club raised these issues with reasonable specificity in its comments submitted to ADEQ in the course of this permit renewal process, Sierra Club has not waived any rights to address these issues, either through comments to ADEQ or through this petition to EPA.

[134] *See* Exs. 22 and 23.

[135] *See* Pre-Existing White Bluff Title V Permit (No. 0263-AOP-R6), Section III, at pdf 18-19 (Ex. 30), which includes the permit history for Permit 0263-AOP-R4 (Ex. 36).

burning of different coals. And there were in all probability other changes to other parts of the plant and/or the White Bluff boilers made to accommodate the burning of different coal.

D. The Change in the Method of Operation At White Bluff Units 1 and 2 to Burn Different Fuels Should Have Been Projected to Result in a Significant Net Emissions Increase of At Least PM, PM10, and SO2.

As shown above, the change in the type of coal burned that was authorized in Permit 0263-AOP-R4 was a change in the method of operation of the White Bluff facility that should have been evaluated for PSD applicability. Has such an analysis been done, it would have shown a significant net emissions increase of at least PM, PM10, and SO2 at each White Bluff unit. To demonstrate this fact, Sierra Club has provided emission calculations below.

Before one can project emissions from the coal switch, one has to determine the baseline emissions. According to the applicable PSD regulations in the Arkansas SIP at the time Permit 0263-AOP-R4 was issued, baseline emissions were to be based on the two years prior to the permit change unless another period is determined to be more representative of normal source operations. 40 C.F.R. § 52.21 (b)(ii) (1994). In this case, although Permit 0263-AOP-R4 was issued in 2006, ADEQ allowed Entergy to test burn other coals during 2005.[136] Entergy submitted its permit application requesting authority to burn different coals and receive coal via barge on July 1, 2005.[137] However, Entergy did not submit an analysis of PSD applicability or

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[136] *See, e.g.*, July 7, 2005 letter from ADEQ to Entergy regarding burning different coals (authorizing Entergy to proceed with the burning of different coals and to receive coal via barge in compliance with current permit limits until the permit is revised) (Ex. 52); August 11, 2005 letter from ADEQ to Entergy allowing Entergy to test burn Columbian coal at White Bluff (Ex. 53).

[137] *See* July 1, 2005 Title V Permit Minor Modification Application (Ex. 54).

baseline emissions with this application, presumably because it maintained that this was a minor permit modification.

Thus, Sierra Club has used 2003-2004 as reflective of baseline emissions before the fuel change for White Bluff Units 1 and 2.[138] For PM and PM 10 emission factors, Sierra Club used the emission factors given in Entergy's July 2006 submittal to ADEQ regarding the White Bluff Unit 1 economizer replacement and in Entergy's August 2007 submittal to ADEQ regarding the White Bluff Unit 2 economizer replacement.[139] Since Sierra Club is aware there were issues with the SO2 CEMS at White Bluff Unit 1 during this period, Sierra Club simply applied a 0.70 lb/MMBtu SO2 emission factor to the average annual heat input over 2003-2004 to determine baseline SO2 emissions. This reflects the average between Entergy's Unit 1 SO2 emission factor of 0.713 lb/MMBtu (in Ex. 22) and Entergy's Unit 2 SO2 emission factor of 0.696 lb/MMBtu (in Ex. 23). Table 8 below provides the results of these calculations of baseline emissions.

Table 8: White Bluff Unit 1 and 2 Baseline Emissions of PM, PM10, and SO2 for 2003-2004 Baseline Period for Coal Switch.

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[138] As previously stated in these comments, the baseline heat input and emissions are inflated because the White Bluff units were operating above their allowable 8700 MMBtu/hr heat input capacity during the baseline period. However, Sierra Club did not attempt to recalculate the baseline emissions to reflect compliance with the 8700 MMBtu/hr limit. By using the actual, improperly inflated, baseline emissions for comparison to post-change emissions, Sierra Club's analysis is more conservative.

[139] *See* July 31, 2006 letter from Entergy to ADEQ regarding the economizer replacement at White Bluff Unit 1, Attachment at 1(White Bluff Unit 1 PM10 emission factor is 0.004 (filterable) plus 0.010 (condensable) for a total of 0.014 lb/MMBtu) (Ex. 22); PM emission factor is 0.015 (filterable) plus 0.010 (condensable) for a total PM factor of 0.025 lb/MMBtu); August 8, 2007 letter from Entergy to ADEQ regarding the economizer replacement at White Bluff Unit 2, Attachment at 1 (White Bluff Unit 2 PM10 emission factor is 0.0034 (filterable) plus 0.0094 (condensable) for a total of 0.0128 lb/MMBtu and PM (filterable) emission factor is 0.015 plus PM (condensable) of 0.0094 for a total PM emission factor of 0.0244 lb/MMBtu) (Ex. 23).

White Bluff	2003-2004 Average Annual Heat Input, MMBtu	2003-2004 Average PM Emissions, tons per year	2003-2004 Average PM10 Emissions, tons per year	2003-2004 Average SO2 Emissions, tons per year
Unit 1	60,513,709	756	424	21,180
Unit 2	56,958,892	695	399	19,936

As discussed above in regard to the Unit 1 economizer replacement, because no reporting of post change emissions was done after the coal switch, applicability to PSD must be based on a comparison of actual emissions before the change to potential emissions after the change. *See* 40 C.F.R. § 52.21(b)(21)(iv) (1994). *See also United States v. Duke Energy Corp.*, 278 F. Supp. 2d 619, 647 n.25 (M.D.N.C. 2003). The PSD significance levels for PM, PM10, and SO2 are 15 tpy, 25 tpy and 40 tpy, respectively. 40 C.F.R. § 52.21(b)(23)(i). In Permit 0263-AOP-R4, ADEQ authorized significant increases in the allowable emission rates of PM and PM10 from each White Bluff unit as discussed above. Thus, based on a comparison of baseline emissions to potential emissions allowed under White Bluff Permit 0263-AOP-R4, the coal switch most assuredly would result in a significant increase in emissions of PM, PM10, and SO2.

Table 9: Analysis of Emission Increases of PM, PM10, and SO2 at White Bluff for the Coal Switch Based on an "Actual-to-Potential Emissions" Applicability Test.

White Bluff	Baseline PM, tpy	Potential PM, tpy	Baseline PM10, tpy	Potential PM, tpy	Baseline SO2, tpy	Potential SO2, tpy	Significant?

Unit 1	756	3,127.4	424	3,127.4	21,180	45,727.2	YES for PM, PM10, SO2
Unit 2	695	3,127.4	399	3,127.4	19,936	45,727.2	

As Table 9 shows, the coal switch at White Bluff should have been projected to result in a significant emission increase of at least PM, PM10, and SO2 at each White Bluff unit. And, given that there have been no contemporaneous emission reductions of PM, PM10, or SO2, the fuel switch should have been projected to result in a significant net emissions increase of PM, PM10, and SO2 as well.

It is also possible that the coal switch would result in significant emission increases of other pollutants such as NOx, if the White Bluff units increase heat input to the boilers (*i.e.*, burn the same tonnage of coal but the coal has higher heat input) although, as previously stated, the currently effective permit limits heat input to the boilers to 8700 MMBtu/hr which would not allow an increase in heat input to the boiler above 8700 MMBtu/hr with the fuel change. NOx emission rates with bituminous coals are also typically higher than with subbituminous coals and, thus, even if the heat input to the boiler did not change, NOx rates might go up with the burning of bituminous coals at White Bluff.[140] Thus, ADEQ should have evaluated PSD applicability for NOx as well as other regulated NSR pollutants for the coal change at White Bluff.

Not only should a significant emissions increase of at least PM, PM10, and SO2 been projected based on an analysis of actual to potential emissions as shown above, but significant

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[140] *See, e.g.*, 40 C.F.R. Part 51, Appendix Y, Table 1. The presumptive NOx emission limits for BART sources are typically higher for bituminous coal-fired units compared to subbituminous coal-fired units.

emission increases of these pollutants should also have been projected with an analysis of actual to representative actual annual emissions. Entergy's July 2006 submittal to ADEQ on the White Bluff Unit 1 economizer replacement contains information on the baseline ash, sulfur and heat value content of the coal used at White Bluff during 2003-2004. The heat value in 2003-2004 averaged 8,550 Btu/lb, the sulfur content averaged 0.355%, and the ash content averaged 5.27%.[141] In February 2006, Entergy submitted new emission rate table and revised calculations for the requested coal changes at White Bluff.[142] In the revised calculations submitted by Entergy, the company identified the following for the coal properties: Ash content = 13.22%, Sulfur Content = 0.72%, Coal heating value = 8286 Btu/lb, coal feed = 525 tons per hour, and heat input = 8700 MMBtu/hr.[143] The comparison between Entergy's projected ash and sulfur content and the sulfur and ash content during the baseline period gives a clear indication that actual and significant emission increases would be projected with the fuel switch.

Based on this, Entergy calculated new PM filterable and condensable emission factors in terms of lb/hr.[144] Sierra Club converted these emission factors to lb/MMBtu by taking the average heat value of the coal into account, and thus Entergy's projected PM lb/hr emission factor equates to 0.04 lb/MMBtu for PM (filterable) and 0.042 lb/MMBtu for PM (condensable), which sums to 0.082 lb/MMBtu for PM total.

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[141] *See* July 2006 Submittal from Entergy to ADEQ, Attachment at 3, Table of Emission Inventory White Bluff (Ex. 22). The average of 2003-2004 data is presented in this letter.

[142] *See* February 21, 2006 email from George Johnson (Entergy) to Ann Sudmeyer (ADEQ) (Ex. 51).

[143] *Id.*, Attachment at 1.

[144] *Id.*

Entergy did not calculate a new PM10 emission rate or a new SO2 emission rate, but instead proposed to "take a PM10 limit equal to PM."[145] However, one can calculate a revised PM10 emission factor based on the data provided by Entergy. AP-42 provides a filterable PM10 emission factor for dry bottom, tangentially-fired boilers like White Bluff of 2.3A lb of filterable PM10 per ton of coal burned, where A is the percentage of ash in the coal.[146] Entergy has assumed a 99.5% removal efficiency for its ESP in its PM emission factor calculation, and Sierra Club assumed the same for PM10. Thus, the revised filterable PM10 emission rate for White Bluff, assuming 13.22% ash and 8286 Btu/hr coal is as follows:

PM10 (filterable) = (2.3 * 13.22 lb/ton) * (1 ton/2000 lb)(1/8286 Btu/lb) *
(10^6 Btu/MMBtu) *(1-0.995) = 0.009 lb/MMBtu

Given that condensable PM is all typically PM2.5 size or smaller, one can simply add Entergy's projected PM condensable emission factor of 0.042 lb/MMBtu to the PM10 filterable emission factor of 0.009 lb/MMBtu to arrive at a PM10 total emission factor of 0.051 lb/MMBtu.

With respect to a projected SO2 emission factor, AP-42 lists two different emission factors for dry bottom tangentially-fired boilers, depending on whether bituminous or subbituminous coal is burned, with the subbituminous coal emission factor being lower.[147] No emission factor is listed for units that blend subbituminous and bituminous coal. To be conservative in this analysis, Sierra Club used the subbituminous coal emission factor of 35S lb/ton. Assuming a heat value of the coal of 8286 Btu/lb and a sulfur content of 0.72%, the

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[145] *Id.*

[146] *See* AP-42, Table 1.1-4.

[147] *See* AP-42, Table 1.1-3.

projected SO2 emission factor would be 1.52 lb/MMBtu. However, this is higher than the applicable NSPS limit of 1.2 lb/MMBtu.[148] Thus, the allowable emissions rate of 1.2 lb/MMBtu must be used for representative actual annual SO2 emissions.

To summarize, based on the data provided by Entergy on post-fuel change coal characteristics, the following emission factors were developed for determining post-change emissions: PM total = 0.082 lb/MMBtu; PM10 total = 0.051 lb/MMBtu; and SO2 = 1.2 lb/MMBtu.

For the purpose of calculating representative actual annual emissions, Sierra Club assumed the heat input remained the same as the 2003-2004 baseline average. However, it is very likely that increases in heat input could occur with the fuel change as discussed above. So this calculation of representative actual annual emissions is again conservative. As Table 10 below shows, with the revised emission factors based on coal characteristic data provided by Entergy and assuming heat input does not change from baseline, the coal switch permitted by ADEQ in 2006 should have been projected to result in a significant emission increase based on the post-change representative actual annual emissions.

Table 10: Analysis of Emission Increases of PM, PM10, and SO2 at White Bluff for the Coal Switch Based on an "Actual-to-Representative Actual Annual Emissions" Applicability Test.

[148] *See* Final White Bluff Title V Renewal Permit, Condition IV.3.c, at pdf 23 (Ex. 72).

White Bluff	Baseline PM, tpy[149]	Post Change PM, tpy	Baseline PM10, tpy	Post Change PM, tpy	Baseline SO2, tpy	Post Change SO2, tpy	Significant?
Unit 1	756	2,481	424	1,543	21,180	36,308	YES for PM, PM10, SO2
Unit 2	695	2,335	399	1,452	19,936	34,175	

Clearly, based on an analysis of actual to representative actual annual emissions, there would be significant emission increases projected for the fuel switch above the PSD significance levels for PM (*i.e.*, greater than 25 tpy), for PM10 (*i.e.*, greater than 15 tpy) and for SO2 (*i.e.*, greater than 40 tpy). 40 C.F.R. § 52.21(b)(23)(i) (1994). And, given that there have been no contemporaneous emission reductions of PM, PM10, or SO2, the fuel switch should have been projected to result in a significant net emissions increase of PM, PM10, and SO2 as well.

E. Summary

As shown above, Entergy's request to change from burning subbituminous coal from northeastern Wyoming to bituminous coal and any subbituminous coals should have been considered a change in the method of operation and subject to PSD applicability review. Had

[149] Note that this analysis was presented in Sierra Club's January 10, 2012 comment letter to ADEQ in Table 7 at 49 (Ex. 68), but incorrect baseline emissions were listed for PM in Table 7 of Sierra Club's comment letter to ADEQ. Tables 5 and 6 of Sierra Club's January 10, 2012 letter to ADEQ (at 46 and 49) listed the correct baseline emissions, as does Table 10 in this petition.

such review been done for the change in fuel requested by Entergy, significant emission increases would have been projected for the coal switch for PM, PM10, and SO2. Accordingly, the Final White Bluff Title V Renewal Permit unlawfully authorizes the fuel switch, as well as the increase in coal sulfur and ash content, that was first unlawfully and erroneously permitted in 2006 in White Bluff Title V Permit (No. 0263-AOP-R4). For this reason, the Administrator must object to the Final White Bluff Title V Renewal Permit and ensure that ADEQ revokes the fuel changes and the increases in sulfur, ash, and PM/PM10 emission limits that it authorized in Permit 0263-AOP-R4 unless and until ADEQ issues a PSD permit and requires BACT for the White Bluff boilers for the significant net emission increases that would have been projected to occur in PM, PM10 and SO2. As it stands now, the Final White Bluff Title V Renewal Permit is legally deficient because it fails to include all applicable requirements of the PSD regulations, including BACT limits for PM, PM10, and SO2 at White Bluff Units 1 and 2 due to the fuel change at White Bluff.

Issue #5: The Administrator Must Object to the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) Because It Unlawfully Fails to Include or Unlawfully Relaxes or Revises Federally Enforceable SIP Limitations on Opacity Applicable to White Bluff Units 1 and 2.

All sources subject to Title V permitting must have a permit to operate "that assures compliance by the source with all applicable requirements." *See* 40 C.F.R § 70.1(b); CAA Section 504(a), 42 U.S.C. § 766lc(a); APCEC Reg. 26.701(A) and 26.102. Applicable requirements are defined in APCEC Reg. 26, Chapter 2, 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 [Clean Air] Act," which includes the EPA-approved

Arkansas SIP limitations on opacity from the boilers at Units 1 and 2 set forth at APCEC Reg. 19, 503(B)(1). *See also* 40 C.F.R. § 70.2; *see generally* Clean Air Act Section 110(a)(2)(C), 42 U.S.C. 7410(a)(2)(C); Clean Air Act Sections 160-69, 42 U.S.C. §§ 7470-7492 ; Clean Air Act Section 173, 42 U.S.C. § 7503; 40 C.F.R. §§ 51.160-66 & 52.21. As explained below, the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) (Ex. 72) fails to include, or unlawfully relaxes or revises, federally enforceable SIP limitations on opacity applicable to White Bluff Units 1 and 2.[150]

A. The Importance of Opacity Limits and the Relationship Between Opacity and PM Emissions

Restrictions on opacity or visible emissions are one of the most basic emission limitations imposed on sources of air pollution. "'Opacity' means the degree to which air emissions reduce the transmission of light and obscure the view of an object in the background." APCEC Reg. 19, Chapter 2, Definitions; *see also Sierra Club v. EPA*, 430 F.3d 1337, 1341 (11th Cir. 2005).

> For example, a plume with 20% opacity blocks 20% of light passing through it; no light passes through a plume with 100% opacity. Opacity is not a pollutant, but instead is a measure of the light-blocking property of a plant's emissions, which is important in the Clean Air Act regulatory scheme as an indicator of the amount of visible particulate pollution being discharged by a source.

Id.

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[150] Sierra Club raised this issue (and all the related issues discussed below) in its January 10, 2012 comment letter to ADEQ on the draft White Bluff Title V renewal permit. *See* 1/10/12 Sierra Club's Additional Comments on the Draft Title V Renewal Permit for the Entergy Arkansas White Bluff Plant (No. 0263-AOP-R7) at 50-62 (Ex. 68).

Every state, including Arkansas, maintains a SIP to "enforce national ambient air quality standards developed by EPA." *Id.* (citing 42 U.S.C. § 7410). Each State Implementation Plan, in turn, must have regulations that limit visible emissions or opacity. 40 C.F.R. § 51.212(b).

An important reason for this opacity regulation requirement is that large sources of air pollution, such as the White Bluff units, can emit an astonishing amount of particulate matter (PM) pollution in a short amount of time. Fortunately, modern pollution controls are capable of reducing these emissions by over 99%. Jacob Katz, P.E., *The Art of Electrostatic Precipitation*, S&S Printing Company, Pittsburgh, 1981, p. 332 (when operating properly, four-field ESPs have expected efficiencies in the range of 99.0 to 99.3 percent).

To keep particulate pollution under control, it is imperative that these highly efficient control devices operate continuously, as required by the Clean Air Act. *Sierra Club v. EPA*, 430 F.3d at 1348. Until recently, however, it has been impossible to know whether PM emission limits are being complied with continuously. Historically, regulators have relied on a two-step control scheme. First, regulators have required elaborate, expensive, and infrequently performed tests that demonstrate that a source can, when operating its pollution controls, comply with PM emission limits. 39 Fed. Reg. 9308, 9309 (March 8, 1974). Second, regulators have imposed opacity standards. Opacity can be evaluated on an instantaneous and continuous basis, thereby providing critical insight into whether pollution controls are being properly maintained and operated. As EPA recently stated in a final rule disapproving an Alabama SIP revision request relating to opacity:

> Historically, visible emissions have been an important tool for implementation of PM NAAQS and, in particular, for the implementation and enforcement of PM limits on sources to help attain the NAAQS.[151] Visible emissions have been a useful tool to indicate overall operation and maintenance (O & M) of a facility and its emissions control devices even before modern instruments that measure PM on a direct, continuous basis existed. The observation of greater than normal visible emissions, particularly on a recurring basis, has served as an indication that incomplete combustion or other changes to the process and/or the control device had or were occurring; such changes frequently led to increased PM emissions. Although opacity is not a criteria pollutant, opacity standards continue to be used as an indicator of the effectiveness of emission controls for PM emissions, or to assist with implementation and enforcement of PM emission standards for purposes of attaining PM NAAQS. Opacity measurements can serve as an indicator of a well-maintained, well-operated source and that such sources should be able to achieve visible emissions that comply with opacity limits.

76 Fed. Reg. 18870, 18,872 (April 6, 2011).

To ensure the effectiveness of this approach, at the dawn of clean air regulation, EPA determined that it was best to make opacity an independently enforceable requirement. 39 Fed. Reg. at 9309. And since approximately the mid-1970's, the Arkansas has imposed an opacity limit.

B. The Arkansas SIP's Opacity Regulations

The current SIP regulation governing opacity is found at APCEC Reg. 19.503 and was most recently approved by EPA on April 12, 2007. 72 Fed. Reg. 18394 (April 12, 2007). It reads in pertinent part as follows:

Section 19.503 Visible emission regulations

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[151] NAAQS is an acronym for National Ambient Air Quality Standard.

(B) No person shall cause or permit visible emissions (other than uncombined water vapor) from new equipment identified hereinunder which was installed or permitted by the Department after January 30, 1972 to exceed the following limitations or to exceed any applicable visible emission limitations of the New Source Performance Standards promulgated by the United States Environmental Protection Agency:

(1) For incinerators and fuel burning equipment, exclusively, emissions shall not exceed 20% opacity except that emissions greater than 20% opacity but not exceeding 60% opacity will be allowed for not more than six (6) minutes in the aggregate in any consecutive 60-minute period, provided such emissions will not be permitted more than three (3) times during any 24-hour period.

(2) For equipment used in a manufacturing process, emissions shall not exceed 20%.

(C) Opacity of visible emissions shall be determined using EPA Method 9 (40 CFR Part 60, Appendix A).

(emphasis added).

The opacity limit set forth at APCEC Reg. 19.503(B)(1) is part of the federally enforceable SIP and governs opacity emissions from White Bluff Units 1 and 2. Significantly, this provision limits opacity from White Bluff Units 1 and 2 to 20% except for three six (6) minute periods in the aggregate in any consecutive 60-minute period so long as those periods do not exceed 60% opacity. *Id.* And this provision does not contain any exemptions for startups, shutdowns, malfunctions or upsets. *Id.*

The Arkansas SIP also contains two other relevant provisions relating to upset and emergency conditions. The upset conditions provision is set forth at APCEC Reg. 19.601. It states as follows:

Section 19.601 Upset conditions

For purposes of this paragraph, "upset condition" shall be defined as exceedences of applicable emission limitations lasting 30 or more minutes, in the aggregate,

during a 24-hour period, unless otherwise specified in an applicable permit or regulation (such as NSPS regulations). All upset conditions, resulting in violation of an applicable permit or regulation, shall be reported to the Department. ***Any source exceeding an emission limit established by the Plan or applicable permit shall be deemed in violation of said Plan or permit and shall be subject to enforcement action. The Department may forego enforcement action for federally regulated air pollutant emissions given that the person responsible for the source of the excess emissions does the following***:

(A) Demonstrates to the satisfaction of the Department that the emissions resulted from:

(1) equipment malfunction or upset and are not the result of negligence or improper maintenance; or

(2) ***physical constraints on the ability of a source to comply with the emission standard, limitation or rate during startup or shutdown***;

And that all reasonable measures have been taken to immediately minimize or eliminate the excess emissions.

(B) Reports such occurrence or upset or breakdown of equipment to the Department by the end of the next business day after the discovery of the occurrence.

(C) Submits to the Department, at its request, a full report of such occurrence, including the identification of and location of the process and control equipment involved in the upset and including a statement of all known causes and the scheduling and nature of the actions to be taken to eliminate future occurrences or to minimize the amount by which said limits are exceeded and to reduce the length of time for which said limits are exceeded.

(emphasis added).

As the express language in first bolded portion of APCEC Reg. 19.601 makes clear, this provision merely sets forth the limited conditions under which ADEQ may choose, in an exercise of enforcement discretion, to forego the pursuit of an enforcement action for emission limit violations when an "upset" (which could include startup and shutdowns if they are due to physical constraints the prevent a source from complying with an applicable limit) as defined by this rule has occurred and when all the other specifically delineated conditions have been

satisfied. This provision does not in any manner modify any aspects of a federally enforceable SIP emission limit, including the opacity limitation set forth at APCEC Reg. 19.503(B)(1). As the rule clearly states, "[a]ny source exceeding an emission limit established by the Plan or applicable permit shall be deemed in violation of said Plan or permit and shall be subject to enforcement action." In other words, the upset rule does not provide an automatic exemption from the SIP opacity limit (or any other limitation), *see* ½0/05 E-mail from ADEQ's A. Sudmeyer to Entergy's G. Johnson (confirming that for compliance purposes there are no automatic exemptions from Arkansas' 20% opacity limitation) (Ex. 56), and the fact that a qualifying upset, including a startup or shutdown, occurs does not excuse the exceedance from being a violation as a matter of law. Since the opacity standard at APCEC Reg. 19.503(B)(1) does not exempt startups and shutdowns (or upsets, malfunctions or emergencies for that matter) from the applicable opacity limit, opacity exceedances are violations even if when they occur during startups and shutdowns that fall within coverage of the upset rule at APCEC 19.603.

Consequently, it also necessarily follows that any decision by ADEQ to forego an enforcement action for an opacity violation occurring during an upset, including a startup or shutdown, does not preclude or prevent EPA or any citizen from taking an enforcement action over the same violation. *See generally* EPA's 1999 Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown ("EPA's SSM Policy") at pdf 3, 6 (http://www.epa.gov/region07/air/ title5/t5memos/excesem2.pdf).

As stated above, the current Arkansas SIP also contains a provision purporting to address emergency conditions. That provision is set forth at APCEC Reg. 19.602 and states as follows:

Section 19.602 Emergency conditions

An "emergency" means any situation arising from the sudden and reasonably unforseeable events beyond the control of the source, including natural disasters, which situation requires immediate corrective action to restore normal operation, and that causes the source to ***exceed a technology-based emission limitation under the permit***, due to unavoidable increases in emissions attributable to the upset condition. ***An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error***.

(A) ***An emergency constitutes a complete affirmative defense to an action brought for noncompliance with such technology-based limitations if the following conditions are met.*** The affirmative defense of emergency shall demonstrate through properly signed contemporaneous operating logs, or such other relevant evidence that:

(1) An emergency occurred and that the permittee can identify the cause(s) of the emergency;

(2) The permitted facility was at the time being properly operated;

(3) During the period of the emergency, the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

(4) The permittee submitted notice of the upset to the Department by the end of the next business day after the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

This Arkansas SIP provision contains conditions that are generally more difficult to satisfy than the upset rule. In order to be applicable, a sudden, reasonably unforeseeable event beyond the control of the source that requires immediate corrective action to restore normal operation must occur which causes the source to exceed a technology-based emission limitation[152] due to unavoidable increases in emissions attributable to the event in question.

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[152] Although, for the purposes of this comment it is not necessary to answer the question, the fact that this provision is limited to violations of technology-based emission limitations begs the

However, where all the conditions are met for its application, including, the submission of a report by the end of the following business day, this provision purports to establish an absolute affirmative defense to any enforcement action addressing violations covered by the emergency provision where an emergency condition as defined in the rule has occurred and all the other specified conditions are fully satisfied.[153] Assuming, *arguendo*, that this provision has potential application to exceedances of the federal enforceable Arkansas SIP's opacity limit at Reg. 19.503, it may, when all the required conditions are met, be relied on to bar any enforcement action over covered exceedances of the Arkansas SIP's opacity limit which are still technically violations of that limit.

B. The NSPS Subpart D Opacity Limit Applicable to White Bluff Units 1 and 2

In addition to the Arkansas SIP's opacity limit at APCEC Reg. 19.503(B)(1), White Bluff Units 1 and 2 are also subject to a different opacity limit imposed by NSPS Subpart D, 40 C.F.R. 60.42(a)(2). Specifically, the NSPS Subpart D opacity limit states in pertinent part that:

> no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that ...[e]xhibit ***greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity***.

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question of whether it is even applicable to the Arkansas SIP's opacity limitation. Sierra Club would submit that SIP provision is a requirement designed to assist Arkansas in complying with the PM NAAQS, which is an air quality-based standard, unlike the emission limits set forth in NSPS Subpart D, which are unquestionably technology-based standards. Consequently, it is possible that the emergency condition provision at APCEC Reg. 19.602 is not applicable to the Arkansas SIP's opacity limit at all.

[153] This SIP provision appears to be inconsistent with EPA's SSM Policy and otherwise unlawful but Sierra Club is not seeking to challenge any EPA-approved SIP provisions in the context of this petition.

Id. (emphasis added). Unlike the SIP opacity limit, this NSPS opacity limit incorporates absolute exceptions for startup, shutdown and malfunction set forth in 40 C.F.R. § 60.11(c).

C. The Final White Bluff Title V Renewal Permit's Opacity Provisions

The Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) at pdf 22-24, 29-30 (Ex. 72) contains the following provisions governing the opacity of emissions from White Bluff Units 1 and 2:

SECTION IV: SPECIFIC CONDITIONS
SN-01, SN-02, & SN-05
Boilers
* * *

Specific Conditions . . .

3. SN-01 and SN-02 are subject to 40 CFR, Part 60, Subpart D, Standards of Performance for fossil fuel-fired steam generators due to a heat input capacity of greater than 250 MMBtu/hr. Applicable provisions of Subpart D (Appendix A) include, but are not limited to the following [Regulation 19, §19.304, and 40 CFR Part 60]: . . .

b. Opacity shall not exceed 20 percent except for one six-minute period per hour of not more than 27 percent opacity and as except as provided by 40 CFR 60.8 and 60.11. [40 CFR 60.42(a)(2)] . . .

f. Excess opacity emissions are defined as any six minute period during which the average opacity emissions exceed 20%, except for one 6 minute average per hour of up to 27% opacity. [40 CFR 60.45(g)(1)] . . .

6. The permittee shall not cause to be discharged to the atmosphere from the boilers any emissions which exhibit an opacity greater than 20 percent when firing coal or No. 2 fuel oil. ***The opacity shall not exceed 20 percent (6-minute average), except for one 6-minute period per hour not to exceed 27 percent.*** Opacity exceedances shall be reported in accordance with Specific Condition #7. [§19.503 of Regulation 19, and 40 CFR Part 52, Subpart E and 40 CFR 60.42(a)(2)]

7. The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) for measuring opacity of emissions and all SO2, NOx, and

CO2 emissions from SN-01 and SN-02 and record the output of the system. The CO2 monitor and analyzer serve as the diluent in this system. This CEMS shall comply with the Air Division's "Continuous Emission Monitoring Systems Conditions". A copy is provided in Appendix B. The permittee shall report all excess emissions as defined by 40 CFR 60.45(g)(1), (2), and (3) and in accordance with 40 CFR 60.7(c).
Except for opacity, the permittee must report all excess emissions including those excess emissions caused by startups, shutdowns, and malfunctions. For opacity, all exceedances must be reported in the quarterly reports including those attributable to startup, shutdown, and malfunction. ***Only those opacity exceedances that are not attributable to startup, shutdown, and malfunction will be used for calculating the percentage of compliance with the NSPS opacity limit. Opacity exceedances would not be reported under §19.601 of Regulation 19 for startup, shutdown, and malfunction. . . .***

28. The opacity for SN-01 and SN-02 shall not exceed 20% opacity except that emissions greater than 20% opacity but not exceeding 60% opacity will be allowed for not more than six (6) minutes in the aggregate in any consecutive 60-minute period, provided such emissions will not be permitted more than three (3) times during any 24-hour period. ***However, the opacity limits imposed by this condition will be held in abeyance provided that opacity does not exceed 20% except that emissions greater than 20% opacity but not exceeding 27% opacity will be allowed for not more than one 6-minute period per hour, provided such emissions will not be permitted more than ten (10) times per day.[]***
Violations of this condition may be allowed as a direct result of unavoidable upset conditions in the nature of the process, or unavoidable and unforeseeable breakdown of any air pollution control equipment or related operating equipment, or as a direct result of shutdown or start-up of the operating unit, provided the following requirements are met:

a. Such occurrence, in the case of unavoidable upset in or breakdown of equipment, shall have been reported to the Department by means of a notification delivered by phone, fax, or email by the end of the next business day after the discovery of the occurrence.

b. The facility shall submit to the Department, at its request, a full report of such occurrence, including a statement of all known causes and of the scheduling and nature of the actions to be taken to minimize or eliminate future occurrences, including, but not limited to, action to reduce the frequency of occurrence of such conditions, to minimize the amount by which said limits are exceeded, and to reduce the length of time for which said limits are exceeded.

c. In the case of shutdown for necessary scheduled maintenance, the intent to shutdown shall be reported to the Department at least twenty-four (24) hours prior to the shutdown; provided, however, that the exception provided by this condition shall only apply in those cases where maximum reasonable effort has been made to accomplish such maintenance during periods of non-operation of any related

source operation or where it would be unreasonable or impossible to shut down the source operation during the maintenance period. Any information which is considered a trade secret under 8-4-308 shall be submitted with an affidavit containing the information of Regulation 18.1402(B).

d. Demonstrates to the satisfaction of the Department that the emissions resulted from:

i. Equipment malfunction or upset and are not the result of negligence or improper maintenance;
ii. Physical constraints on the ability of a source to comply with the emission standard, limitation or rate during startup or shutdown;

And that all reasonable measures have been taken to immediately minimize or eliminate the excess emissions. Opacity exceedances shall be reported in accordance with General Provision #7. [§18.102(C), §18.501, and §18.1101 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311] . . . .

(emphasis added).

D. The Final White Bluff Title V Renewal Permit is Unlawful Because it Fails to Identify the Arkansas SIP's Opacity Limit as a Fully and Independently Applicable Requirement in Addition to NSPS Subpart D Opacity Limit and Because the Hybrid Opacity Limitation Created in the Permit at Condition No. 28 Is Less Stringent Than Either the Arkansas SIP Opacity Limit or the NSPS Subpart D Opacity Limit.

At Condition 3.b of the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) at pdf 23 (Ex. 72), the NSPS Subpart D opacity limit at 40 C.F.R. § 60.42(a)(2) (including exemptions in 40 C.F.R. § 60.8 and 60.11) is set forth as an applicable requirement for White Bluff Units 1 and 2. This standard is reflected in other provisions of the permit pertaining to Units 1 and 2 as well. However, instead of also identifying and accurately describing the other federally enforceable opacity limitation applicable to White Bluff Units 1 and 2, that is, the Arkansas SIP opacity limit at APCEC Reg. 19.503(B)(1), the Final White Bluff Title V Renewal Permit identifies that SIP opacity limit only to immediately sublimate that limit and expressly hold it in abeyance in favor of a modified or hybrid version of the NSPS Subpart D opacity limit.

Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition 28, at pdf 29-30 (Ex. 72).

Specifically, after the recitation of the Arkansas SIP opacity limit, Specific Condition 28 states in pertinent part:

> However, the opacity limits imposed by this condition will be held in abeyance provided that opacity does not exceed 20% except that emissions greater than 20% opacity but not exceeding 27% opacity will be allowed for not more than one 6-minute period per hour, provided such emissions will not be permitted more than ten (10) times per day. ***Violations of this condition may be allowed as a direct result of unavoidable upset conditions in the nature of the process, or unavoidable and unforeseeable breakdown of any air pollution control equipment or related operating equipment, or as a direct result of shutdown or start-up of the operating unit***,[154] provided the following requirements are met: . . .

Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) at 29-30 (emphasis added) (Ex. 72). As drafted, this provision appears to provide that (1) so long as White Bluff Units 1 and 2 comply with modified or hybrid opacity standard of 20% opacity with one excused exceedance up to 27% per hour but no more than ten (10) such excused exceedances per day, then the units

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[154] Parts of this hybrid opacity limit -- the exemption for startups, shutdowns and malfunctions -- reflects standard NSPS exclusions from the opacity standard. 40 C.F.R. § 60.11(c). However, this provision also articulates new unlawful absolute exemptions which provide for the allowance of violations occurring as a result of (1) upset conditions in the nature of the process and (2) unavoidable and unforeseeable breakdowns of control or operating equipment. Although these exemptions appear to have been derived to some extent from the "upset conditions" and "emergency conditions" provisions of the SIP at APCEC Reg. 19.601 and 19.602, their language does not precisely track either the Arkansas SIP or NSPS Subpart D. As expressed in the hybrid opacity limit at Specific Condition 28, the "upset conditions" provision of the Arkansas SIP appears to have morphed from a description of how enforcement discretion would be exercised into an absolute legal exemption. And, in the case of the emergency provision, instead of being couched as an absolute affirmative defense to be asserted (or waived) and proven by a defendant, the provision has been converted into a legal exemption or exclusion from liability in the first instance.

do not have to comply with the SIP opacity limit and (2) any violations of this modified or hybrid opacity limit are allowed -- in other words completely excused -- if (3) those exceedances are the "direct result of unavoidable upset conditions in the nature of the process, or unavoidable and unforeseeable breakdown of any air pollution control equipment or related operating equipment, or as a direct result of shutdown or start-up of the operating unit," (4) so long as another series of conditions are met.[155]

This approach is unlawful for a number of reasons. The most basic is that it does identify the Arkansas SIP's opacity as a applicable requirement that is independently applicable and federally enforceable requirement for Units 1 and 2. Because the hybrid opacity limit does not assure full compliance with all the requirements of both the NSPS Subpart D opacity limit and the equally applicable Arkansas SIP opacity limit, the Arkansas SIP's opacity limit had to be included in the final Title V permit but was not. For these reasons, the Final White Bluff Title V Renewal Permit is unlawful.

The only conceivable explanation for creating the modified NSPS Subpart D opacity limit in place of the Arkansas SIP opacity limit was to "streamline" the two applicable opacity limitations applicable to Units 1 and 2 into a single set of requirements.[156] In certain

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[155] Even if an absolute exception was subject to ADEQ's director's discretion, the legal arguments set forth below remain fully applicable and, because the permit allows for the same violations to be absolutely exempted, this provision remains unlawful for all the reasons set forth herein.

[156] It appears that the most problematic opacity provisions were a product of a negotiated compromise between ADEQ and Entergy which may have been first reflected in White Bluff Plant's Title V Operating Permit 0263-AOP-R3 in 2005. *Compare* White Bluff Title V Permit No. 0263-AOP-R2 at 12-15 with White Bluff Plant's Title V Operating Permit 0263-AOP-R3 at 28, ¶27; *see also* 3/31/05 E-mail from Entergy's G. Johnson to ADEQ's M. Bonds *et al.* at 1

circumstances not present here, EPA has allowed such streamlining. *See generally* 3/5/95 EPA White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program from Lydia N. Wegman, Deputy Director, Office of Air Quality Planning and Standards to Director, Office of Ecosystem Protection, Region I *et al.* ("White Paper 2") at 2, pdf 7 through 16, pdf 21 (providing guidance on proper procedures for streamlining Title V permit requirements) (Ex. 60). For streamlining to be appropriate and lawful, the streamlined limit must still "assure compliance with ***all applicable requirements***." *Id.* at Cover Memo at 2, pdf 2 (emphasis added); at White Paper at 11, n. 9, pdf 16 ("Title V allows for the establishment of a streamlined requirement, provided that it assures compliance with all applicable requirements it subsumes."). There are two ways that this can be accomplished, either by allowing a permit to specify compliance with a clearly more stringent limit or "[i]f no one requirement is unambiguously more stringent than the others," by allowing for the creation of a hybrid permit provision in a Title V permit which synthesizes multiple applicable requirements into one limit that ensures compliance with all aspects of all applicable requirements. *Id.* at White Paper at 2, pdf 7, at 8-9, pdf 13-14 (providing guidance on proper procedures for demonstrating equivalent stringency Title V permit requirements), at 11-12, pdf 16-17 (providing guidance for situations "where it is difficult to determine a single most stringent applicable emissions limit by

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(reflecting negotiations between ADEQ and Entergy on SIP and NSPS opacity provisions and referring to change in NSPS opacity standard as a "reasonable compromise.") (Ex. 57); 2/3/05 E-mail String Between Entergy's G. Johnson to ADEQ's T. Rheaume and M. Porta at 1-2 (reflecting Entergy's arguments for why the Arkansas SIP and NSPS opacity limits should not both apply and be included in White Bluff Title V permit, ADEQ's rejection of that argument and indication that White Bluff's prior Title V permits that failed to include the Arkansas SIP's opacity limit were "inaccurate") (Ex. 58); 3/1/05 Entergy's Comments on White Bluff Final Air Permit (0263-AOP-R3) at 1-2 (Ex. 59).

comparing all the applicable emissions limits with each other" and discussion option of creating an alternative hybrid limit"), at 13-16, pdf 18-21 (process for assessing stringency and establishing limit). The hybrid opacity limit at Condition 28 of the Final White Bluff Title V Renewal Permit does neither.

The hybrid opacity limit in Specific Condition 28 of the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) does not impose equal or more stringent opacity requirements on White Bluff Units 1 and 2 than the Arkansas SIP opacity limit at APCEC Reg. 19.503(B)(1).[157] This is because, first and foremost, the Arkansas SIP opacity limit is not subject to an absolute exemption for startups and shutdowns while the hybrid opacity limit does allow exceedances of that limit to be excused where they are a direct result of a startup and shutdown. Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7), Condition 28 at pdf 30 ("Violations of this condition may be allowed . . . as a direct result of shutdown or start-up of the operating unit ....") (Ex. 72). Under the hybrid opacity limit, an unlimited number of opacity exceedances resulting from startups and shutdowns are excused which would be exceedances under the Arkansas SIP limit,[158] and the magnitude of those opacity exceedances are not limited

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[157] No demonstration appears to have been set forth publicly that attempts to show that either the standard NSPS Subpart D opacity limit or the hybrid opacity limit in Specific Condition 28 was equally as stringent as the Arkansas SIP's opacity limit. Without such a demonstration, it was unlawful and remains unlawful to have effectively replaced the Arkansas SIP opacity limit with the hybrid opacity limit in Specific Condition 28.

[158] The Arkansas SIP opacity limit is subject to the Arkansas SIP's upset conditions provision, APCEC Reg. 19.601, but that in no excuses any opacity violation. Instead, it merely provides assurances about how ADEQ will exercise is enforcement discretion when upsets, including startups and shutdowns occur. And although the emergency condition provision at APCEC Reg. 19.602 is applicable to Arkansas SIP opacity exceedances and provides an affirmative defense if all applicable conditions are satisfied, similar (but different conditions) are largely covered in the hybrid opacity limit so that there would appear to be little difference between the two provisions

in any manner, meaning that every one could potentially be 100% opacity.[159] And startups and shutdowns can last for many hours or theoretically even days in certain circumstances. *See generally* 8/27/07 Entergy Emergency Shutdown Report to ADEQ at 1 (reflecting 6-hr. startup) (Ex. 61); Entergy Opacity Exceedance Report for 7/01/07 - 9/30/07 at 1 (*e.g.*, showing opacity exceedances at White Bluff Unit 2 of 100%, 90%, 79.8%, 78.2%, and 68.8% on 7/7/07 and 7/8/07) (Ex. 62). For these reasons, the hybrid opacity limit at Specific Condition 28 is substantially less stringent than the Arkansas SIP opacity limit. *See* 3/1/05 Entergy's Comments on White Bluff's Final Air Permit (0263-AOP-R3) at 2 (Entergy admits as much by adamantly contending that the state law only opacity standard found at APCEC Reg. 18.501, which is identical the Arkansas SIP opacity limit in terms of exclusions/exemptions and the magnitude of opacity emissions allowed, is more stringent than the NSPS Subpart D opacity limit).

In addition, the hybrid opacity limit is also less stringent than the Arkansas SIP's opacity limit because the Arkansas SIP opacity limit only allows for excursions from 20% opacity (up to 60% opacity) no more than once in any consecutive 60-minute period and only three (3) times per 24-hour period, while the hybrid opacity limit allows up to ten (10) exceedances of the 20% limit per day (up to 27% opacity). Thus, seven (7) more opacity exceedances are allowed under the hybrid opacity limit.

Finally, the time frames over which excused exceedances are evaluated also make the hybrid opacity limit less stringent that the Arkansas SIP opacity limit. The hybrid opacity limit

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in that one respect.

[159] In certain situations, emissions of opacity from such large boilers at 100% could potentially be associated with PM emissions that might even threaten to cause PM NAAQS violations.

allows an opacity excursion once ***per hour*** up to 27% opacity and but no more than ten (10) such excused opacity exceedances ***per day*** are allowed. The Arkansas SIP's opacity limit allows an opacity excursion once ***in any consecutive 60-minute period*** up to 60% opacity but no more than three (3) such excused opacity exceedances ***per 24-hour period*** are allowed. Because of these differences, it is possible for what would otherwise be a violation of the Arkansas SIP's opacity limit to be excused under the hybrid opacity limit in Specific Condition 28 of the Final White Bluff Title V Renewal Permit.

For example, if two opacity exceedances which both averaged 25% opacity occurred within one 60-minute consecutive period but occurred in different hours, one of them would constitute a violation of the Arkansas SIP's opacity limit but both would be exempt under the hybrid opacity limit's once per hour exemption. Similarly, if four opacity exceedances which each averaged 25% opacity and otherwise fell within the once per hour up to 60% opacity exemption of the Alabama SIP opacity limit occurred within a consecutive 24 hour period but half occurred on one day and the half occurred on another, one of those violations would constitute a violation of the Alabama SIP's opacity limit. However, under the hybrid opacity limit, all four opacity exceedances would be excused. This is another illustration of how the hybrid opacity limit is less stringent that the Arkansas SIP's limit.

As explained above, the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) fails to adequately set forth all applicable requirements relating to opacity or to identify a set of opacity requirements that are other adequate to lawfully ensure compliance with all applicable opacity requirements. For this reason, the Final White Bluff Title V Renewal Permit is

technically inadequate and unlawful as written and, accordingly, the Administrator is obligated to object to it.[160]

Issue #6: The Administrator Must Object to the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) Because It Fails to Include Applicable Maximum Achievable Control Technology Requirements.

On December 16, 2011, the EPA signed[161] final rules establishing mercury and air toxic maximum achievable control technology (MACT) standards for existing electric utility generating units such as White Bluff. The MACT standards set emission limits for three categories of hazardous air pollutants (HAPs): (1) non-mercury metal HAPs, for which EPA has specified a limit on filterable PM as a surrogate, or limits on HAP metals that must be met; (2) acid gas HAPs, for which EPA has adopted a limit on hydrogen chloride (HCl) or SO2 as a surrogate for all acid gas HAPs; and (3) mercury, for which EPA has established a direct limit. Specifically, for coal-fired boilers burning such as White Bluff, the MACT standards will require Units 1 and 2 to meet a mercury limit of either 1.2 lb/TBtu or 1.3 x 10^{-2} lb/GW-hr. For non-

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[160] In its August 2012 Final Response to Comments at 14; ADEQ asserts that Sierra Club's comments addressing opacity limits have been waived because Sierra Club failed to submit comments and address these issues when this version of the opacity limitations and conditions were allegedly first incorporated into White Bluff's Title V permit, in White Bluff Title V Permit (No. 263-AOP-R3), issued in 2005. As discussed previously, this is a permit renewal process where Sierra Club is entitled to address any aspect of the permit that it believes is objectionable. *See generally In the Matter of Wisconsin Public Service Corporation - Weston Generating Station*, Permit No. 73700902 & P02, Petition No. V-2006-4, Order at 5-7 (Ex. 89). Since Sierra Club raised these issues with reasonable specificity in its comments submitted to ADEQ in the course of this permit renewal process, Sierra Club has not waived any rights to address these issues, either through comments to ADEQ or through this petition to EPA.

[161] *See* EPA's website on Air Toxics Standards for Utilities for the signed rule and further information at http://www.epa.gov/ttn/atw/utility/utilitypg.html. As of the date of this comment letter, the final rulemaking had not yet been published in the Federal Register.

mercury HAP metals and acid gas HAPs, sources have several options as shown in Table 11 below.

Table 11. MACT Standards Applicable to White Bluff Units 1 and 2[162]

HAP Category	MACT Standard	
Non-Mercury HAP Metals (Sources can choose one of three options)	*PM(filterable)*	3.0 x 10^{-2} lb/MMBtu or 3.0 x 10^{-1} lb/MW-hr
	Total of Non-Mercury HAP Metals	5.0 x 10^{-5} lb/MMBtu or 5.0 x 10^{-1} lb/GW-hr
	Individual Non-Mercury Metal HAPs	Limits on each specific metal HAP as specified in Table 2 of 40 C.F.R. Part 63, Subpart UUUUU
Acid Gas HAPs (Sources can choose one of two options)	*Hydrogen Chloride (HCl)*	2.0 x 10^{-3} lb/MMBtu or 2.0 x 10^{-2} lb/MW-hr
	SO2	2.0 x 10^{-1} lb/MMBtu or 1.5 lb/MW-hr
Mercury		1.2 lb/TBtu or 1.3 x 10^{-2} lb/GW-hr

Compliance with these limits will be required at White Bluff within three (3) years of the effective date of the rule, or by 2015. *See* 40 C.F.R. § 63.9984(b).[163]

Given that the 5 year term of the Final White Bluff Title V Renewal Permit will encompass this compliance time frame, Sierra Club commented to ADEQ that it must include the applicable emission limits and compliance schedule, along with the applicable monitoring,

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[162] *See* Table 2 (Emission Limits for Existing EGUs) of 40 C.F.R. Part 63, Subpart UUUUU, under "1. Coal-fired unit not low rank virgin coal" in the December 16, 2011 signed final Mercury and Air Toxics Rulemaking at 1000, available at http://www.epa.gov/mats/pdfs/20111216MATSfinal.pdf.

[163] *See* December 16, 2011 signed final Mercury and Air Toxics Rulemaking at 1000, available at http://www.epa.gov/mats/pdfs/20111216MATSfinal.pdf, at 874. There is the possibility of a one year extension to comply with the MACT standards. *Id.* at 771.

recordkeeping, and reporting requirements, to ensure compliance with the MACT emission limits now applicable to the White Bluff facility.[164]

Because the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7) fails to include these applicable MACT requirements, the permit is technically inadequate and unlawful. Accordingly, Sierra Club petitions EPA to object to the Final White Bluff Title V Renewal Permit because if fails to incorporates the applicable requirements of the utility MACT rule that will become applicable to White Bluff Units 1 and 2 during the 5 year term of their Title V permit.

CONCLUSION

For the reasons set forth above, this petition should be granted and the Administrator should issue an objection to the Final White Bluff Title V Renewal Permit (No. 0263-AOP-R7).

Respectfully submitted,

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[164] *See* 1/10/12 Sierra Club's Additional Comments on the Draft Title V Renewal Permit for the Entergy Arkansas White Bluff Plant (No. 0263-AOP-R7) at 63-64 (Ex. 68).

CERTIFICATE OF SERVICE

I, William J. Moore, III, certify on August 29, 2012, I sent via overnight delivery and e-mail a true and accurate copy of the foregoing document and all exhibits to the following addresses listed below:

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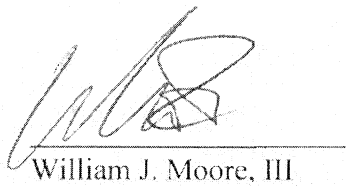

William J. Moore, III

Exhibit Number	Description
1	October 20, 2009 Entergy Title V Renewal Application for White Bluff
2	Permit No. 0263-AOP-R6
3	White Bluff Permit Application Forms for SN-01 and SN-02, submitted by Entergy to ADEQ in a March 2, 2006 e-mail
4	April 22, 1996 White Bluff Permit Application, Emission Rate Tables for SN-01 and SN-02
5	Permit No. 263-AOP-R1
6	Permit No. 0263-AR-1
7	June 20, 2011 E-mail from George Johnson to Thomas Rheaume.
8	January 1991 White Bluff Permit Application
9	October 4, 2006 letter from EPA to ADEQ
10	January 2009 Application for Permit to Construct Entergy White Bluff Units 1 & 2 Air Pollution Control Project
11	FERC Form 1 Supplement Annual Report of the Entergy Arkansas, Inc., For the Year Ending December 31, 2009
12	Arkansas Electric Cooperative Corporation's 2009-2012 Rural Utilities Service (RUS) Generation Construction Work Plan and Request for RUS Approvals, submitted to the Rural Utilities Service August 10, 2009, at Part III, Item III, Tables for White Bluff Unit 1 and for White Bluff Unit 2
13	October 23, 2006 Testimony of Dori J. Costa, on behalf of Constellation Power Source Generation, Inc., Before the Public Service Commission of Maryland (Case No. 9075)
14	Dreier, Jr., D.W., Upgradable Opportunities for Steam Turbines, GE Power Systems, Schenectady, NY, GER 3693D
15	July 31, 2006 letter from Entergy to ADEQ regarding the economizer replacement at White Bluff Unit 1
16	December 7, 2007 letter from Entergy to ADEQ regarding the economizer replacement at White Bluff Unit 2