BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF THE DRAFT OPERATING AIR QUALITY PERMIT FOR ENTERGY ARKANSAS, INC. - INDEPENDENCE PLANT ISSUED BY THE ARKANSAS DEPARTMENT OF ENVIRONMENTAL QUALITY	))))))))))	Permit No. 0449-AOP-R7

SIERRA CLUB'S PETITION TO OBJECT TO THE DRAFT TITLE V OPERATION PERMIT FOR THE INDEPENDENCE PLANT ISSUED BY THE ARKANSAS DEPARTMENT OF ENVIRONMENTAL QUALITY

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 draft Title V permit for Energy-Arkansas, Inc.'s ("EAI" or "Entergy") Independence plant, Permit Number 0449-AOP-R7, that was issued by the Arkansas Department of Environmental Quality ("ADEQ") in July 2010. (A copy of the challenged draft Title V permit is attached hereto as Ex. 1).

The draft Title V permit (also referred to by ADEQ as the draft "operating air permit") at issue in this petition is a renewal of the operating permit for the existing Independence power plant and associated equipment with currently identified generating capacity of 1,700 megawatts ("MW"). The facility's existing operating permit, identified as #0449-AOP-R6, expired on June 2, 2010.[1] The facility is located in Newark, Arkansas.

---

[1]Presumably EAI continues to operate the Independence facility under an "application shield." Its Title V renewal application was submitted to ADEQ in November 2009 (Ex. 2). We have not evaluated the viability of any such application shield for the Independence facility.

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 700,000 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:

> 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 Independence Plant and those members' aesthetic, recreational, environmental, economic and health-related interests will be injured and otherwise adversely impacted if the Independence Plant is allowed to continue to operate and emit air pollutants at the levels contemplated by the challenged draft Title V permit.

PROCEDURAL BACKGROUND

The draft Independence Title V permit is a renewal of the facility's operating permit. The previous operating permit, Permit 0449-AOP-R6, expired on June 2, 2010. EAI submitted a Title V permit renewal application to ADEQ in November 2009 (Ex. 2). ADEQ issued a draft Title V permit for Independence for public review and comment in July 2010 (Ex. 1). Sierra Club submitted comments to ADEQ on the draft Title V permit renewal for Independence on August 9, 2010. *See* August 9, 2010 Letter from William J. Moore, III, on behalf of Sierra Club, to Teresa Marks, Director of ADEQ, and Joseph Hurt, Engineer, ADEQ ("Sierra Club Comments to ADEQ and Exhibits") (Ex. 3).

At the same that ADEQ published the public notice regarding to the Independence Title V Permit, ADEQ submitted the draft Independence Title V permit to EPA for a 45-day review period, which EPA Region VI customarily allows to run concurrent with the public's review of draft Title V permits. *But see* APCEC Reg. 26.603(A). Consistent with this arrangement, EPA Region VI's permit website provided that EPA's 45-day review period on the draft Independence permit ended on August 20, 2010 and that the public petition deadline ends on October 20, 2010. *See* EPA Region VI Air Permit Petition Deadlines (http://yosemite.epa.gov/r6/Apermit.nsf/AirAR?OpenView&Start= 1&Count =4000 &Expand=1#1) (Ex. 4).

Petitioners base their petition on their comments filed on August 9, 2010 (including all exhibits). Sierra Club Comments to ADEQ and Exhibits (Ex. 3). Because proceedings regarding the draft permit are still ongoing and no final permit has been issued yet, Petitioners reserve the right to supplement or revise this petition as necessary and appropriate.[2]

[2] As discussed *infra*, Sierra Club has recently obtained an large amount of additional relevant documents and data from ADEQ, including, most notably, an October 7, 2010 response to Sierra Club's comments on the draft Independence Title permit, emissions calculations from EAI, and a draft response to comments from ADEQ. The permitting process is still moving forward, several critical determinations by ADEQ are yet to be made, and relevant documents

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 Independence without an operating 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

---

and data may still be produced and reviewed. As consequence, Sierra Club expressly reserves the right to supplement this petition as appropriate once it has had to opportunity to fully review and analyze the new documents and data obtained from ADEQ and after ADEQ makes its final determinations regarding the draft Independence Title V permit.

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 participation 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. It is being filed within sixty days from the end of EPA's 45-day review period as required by Clean Air Act § 505(b)(2) and 40 C.F.R. § 70.8(d); *see also* APCEC Reg. 25.606. Accordingly, the Administrator must grant or deny this petition within sixty (60) days after it is filed. 42 U.S.C. § 7661d(b)(2). If the Administrator determines that the draft Independence Title V 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).

GROUNDS FOR OBJECTION

Issue #1: The Administrator Must Object to the Independence Title V Permit Because it Fails to Include Terms and Conditions of the PSD Permit Issued for the Construction of Independence by EPA in 1978.

The EPA issued a PSD permit for the construction and operation of the Independence Station on March 30, 1978. However, the draft Title V permit for the Independence facility fails to include adequate terms and conditions to ensure compliance with the requirements of the 1978 PSD permit. Therefore, the Independence permit is deficient, and EPA must object to the Independence permit due to failure of the permit to assure compliance with all applicable requirements.

A. Background

Title V permits must contain adequate terms and conditions to assure compliance with all applicable requirements of the Clean Air Act. *See* 40 C.F.R. § 70.6(a)(1); APCEC Reg. 26.701(A); *see also* APCEC Reg. 26.402(B)(4)(a); APCEC Reg. 26.703 (A) and (B)(4). "Applicable requirements" include:

> Any term or condition of any preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C or D, of the Act. . . .

See 40 C.F.R. § 70.2 (paragraph (2) of definition of "applicable requirement"); APCEC Reg. 26, Chapter 2 (definition of "applicable requirement").

EPA issued a PSD permit for the construction and operation of the Independence Steam Electric Station on March 30, 1978.[3] That permit included, *inter alia*, the following conditions:

> 2. X The source shall meet the requirements for the application of best X available control technology as follows: X
>
> a. The source shall comply with the requirements of the New Source Performance Standards (NSPS) for Solid Fossil Fuel-fired Steam Generators (40 CFR, Part 60, Subpart D) except that the maximum emissions of TSP and SO2 shall be 0.04 and 0.93 lbs/10^6 Btu, respectively.
>
> b. X The source shall comply with the NSPS for Coal Preparation Plants (40 CFR, Part 60, Subpart Y).
>
> 3. The maximum emission rates of [sulfur dioxide or "SO2"] and [total suspended particulate or "TSP"] shall not exceed 15,510 lbs SO2/hr and 611 lbs TSP/hr based on the use of coal with a heat content of 8,700 Btu/lb and a maximum sulfur and ash content of 0.45% and 8%, respectively . . .

March 30, 1978 PSD Permit PSD-AR-48 at 2 ("1978 PSD Permit").

EPA's 1978 PSD permit remains in effect unless rescinded or revoked by EPA. 40

[3] A copy of this permit is attached as Exhibit 5.

C.F.R. § 52.21(q), (u) and (w); 40 C.F.R. § 124.5(g)(2) ("PSD permits may be terminated only by rescission under §52.21(w) or by automatic expiration under §52.21®)."). And there is no record that the EPA-issued PSD permit for Independence has ever been rescinded or revoked by EPA.

B. The Independence Title V Renewal Permit Allows SO2 and Particulate Emissions in Excess of the SO2 and TSP Emission Limits in the 1978 PSD Permit

The Title V renewal permit for the Independence Station fails to incorporate the combined maximum emission limit of SO2 from Units 1 and 2 of 15,510 pound per hour ("lb/hr") of the 1978 PSD permit. *See* 1978 PSD Permit, Condition 3 (Ex. 5). Further, the Title V permit fails to incorporate the combined maximum emission limit of TSP from Units 1 and 2 of 611 lb/hr. Sierra Club commented on these deficiencies in its August 9, 2010 comment letter to ADEQ (Ex. 3 at 2-3).

According to the Permit History in Section III. of the Title V Permit, these lb/hr limits from the 1978 PSD permit were increased by ADEQ in Permit 449-AR-1 issued April 9, 1991.[4] Specifically, ADEQ increased the lb SO2/hr limit from 15,510 lb/hr to 16,182 lb/hr (8,091 lb/hr per unit) and ADEQ increased the lb TSP/hr limit from 611 lb/hr to 696 lb/hr (348 lb/hr for each unit). *See* Title V Permit at 15 (Ex. 1). Section IV.2. of the Title V permit thus has a limit for SO2 for each unit of 8,091 lb/hr and a limit on filterable PM (i.e., "particulate matter") of 348 lb/hr. *Id.* at 19. These limits allow SO2 and TSP in excess of that allowed under the 1978 PSD permit.

ADEQ improperly authorized these emission increases. A permitting authority cannot

[4] A copy of this permit (0449-AR-1) is attached as Ex. 6.

change emission limitations and requirements of a PSD permit, especially not to increase emissions, without issuing a PSD permit modification that complies with all of the PSD permitting requirements. As part of the PSD permit modification when PSD limits are being increased, the permitting authority is required to evaluate best available control technology ("BACT") based on currently available technologies and techniques.[5]

Permit 449-AR-1 does not indicate what state regulation it was issued under, but it does not appear to be a PSD permit. If it was issued as a PSD permit, it was required to include a re-evaluation of BACT for the Independence units. And such a re-evaluation of BACT for SO2 in 1991 would have required installation of scrubbers for SO2 control.[6] No such evaluation of BACT was provided or discussed in the permit summary, and no new SO2 or PM requirements were included in the permit. In fact, the permit allowed for an increase in SO2 and PM emissions. Thus, it is inconceivable that it was based on any evaluation of BACT made at the time of permit issuance.

Furthermore, as stated above, the PSD permit issued by EPA in 1978 has never been rescinded or revoked by EPA. Therefore, it remains in full effect. Consequently, even if Permit 449-AR-1 was issued under the PSD permitting regulations of the Arkansas SIP, such an ADEQ-

---

[5] *See, e.g.*, the November 19, 1987 EPA Memorandum from Gary McCutcheon and Michael Trutna, EPA, to J. David Sullivan with subject "Request for Determination on Best Available Control Technology (BACT) Issues – Ogden Martin Tulsa Municipal Waste Incinerator Facility," available on EPA's New Source Review Policy and Guidance internet site at http://www.epa.gov/region07/air/nsr/nsrmemos/ogden.pdf.

[6] This is because BACT can be no less stringent than the applicable NSPS for the source category in question and Subpart Da of the NSPS, which applies to new or modified electric utility steam generating units constructed or modified after September 18, 1978 requires installation of a scrubber to meet SO2 standards. *See* 40 C.F.R. § 60.40Da(a)(2) and § 60.43Da.

issued permit cannot change or otherwise override the terms of EPA's 1978 PSD permit issued under 40 C.F.R. § 52.21 unless and until EPA rescinds that permit, which EPA has not done.[7]

Therefore, the Title V renewal permit fails to assure compliance with the applicable requirement of the 1978 PSD permit. EPA must object to the Independence Title V permit because it fails to assure compliance with the 1978 PSD permit issued by EPA.

C. The Independence Title V Renewal Permit Fails to Require Compliance with the New Source Performance Standards for Coal Preparation Plants

The Independence Title V renewal permit also fails to include any requirements that the Independence facility comply with the New Source Performance Standards ("NSPS") for coal preparation plants. This is required in the 1978 PSD permit in Condition 2.b. as a BACT requirement. Sierra Club commented on this deficiency in its August 9, 2010 comment letter to ADEQ (Ex. 3 at 2-3).

According to the Permit History in Section III of the Title V permit, ADEQ removed this requirement Permit 449-AR-1 issued April 9, 1991 "because the facility commenced construction before the applicable date."[8] As previously stated, the 1978 PSD permit cannot be revised unless revoked or rescinded by EPA or unless a PSD permit modification is issued by ADEQ with a new BACT evaluation. Permit 449-AR-1 was not a PSD permit modification and it did not include a new BACT evaluation.

---

[7]While ADEQ issued a permit for the Independence facility in 1991 (Permit 0449-AR-1, Ex. 6) for which the "Summary Report" states that all previous permits are rescinded (see Summary Report Relative to Permit Application for Permit 449-A-1 at 6 (Ex. 6)), ADEQ's Permit 0449-AR-1 cannot have lawfully rescinded EPA's 1978 PSD permit. Only EPA can rescind its PSD permit.

[8] *See* Section III. of Title V permit at 15 (Ex. 1).

Therefore, the Title V renewal permit fails to assure compliance with the applicable requirements of the 1978 PSD permit. EPA must object to the Independence Title V permit because it fails to assure compliance with the requirement in the 1978 PSD permit that the Independence facility comply with 40 C.F.R. Part 60, Subpart Y.

D. The Independence Title V Permit Fails to Assure Compliance with the Limitations on Coal Characteristics of the 1978 PSD Permit.

The Independence Title V permit fails to include terms and conditions necessary to ensure compliance with the limitations on the coal burned at the Independence Station of the 1978 PSD permit. As stated above, Condition 3 of the 1978 PSD permit limits the emission rates of SO2 and TSP "based on the use of coal with a heat content of 8,700 Btu/lb and a maximum sulfur and ash content of 0.45% and 8%, respectively." *See* Condition 3 of 1978 PSD Permit at 2 (Ex. 5). These limits necessarily had to be imposed as supplemental requirements to ensure BACT was complied[9] with or as requirements to ensure the PSD increments and/or NAAQS were complied with. Regardless of the basis for this condition, the specification of the heat value, sulfur and ash content of the coal in this condition was clearly relied upon to show how compliance with this condition would be achieved as is required by the PSD provisions of the Clean Air Act. *See* 42 U.S.C. §§ 7475(a)(3) and 7410(j). Given that this condition identifies a "maximum sulfur and ash content of 0.45% and 8%," these limitations should have been incorporated as specific limitations of Independence's Title V permit. Sierra Club commented on this deficiency in its August 9, 2010 comment letter to ADEQ (Ex. 3 at 2-3).

---

[9] In fact, as shown further below, documentation prepared by EPA shows that these coal characteristics correlate to the 0.93 lb/MMBtu SO2 limit and the 0.04 lb/MMBtu TSP limit of the 1978 PSD permit.

Not only does the Independence Title V renewal permit fail to include these limitations on sulfur and ash content, the permit actually allows the use of coal with higher sulfur and ash content than specified in the 1978 PSD permit. Specifically, Condition IV.30 of the draft Independence Title V permit states: "The ash content of the coal or coal blend shall not exceed 15.96 lb/MMBtu. The sulfur content of the coal or coal blend shall not exceed 0.66%, unless the following equation can be met . . . ." Draft Independence Title V Permit at 28-29 (Ex. 1). An ash content limit of 15.96 lb/MMBtu equates to 13.9% ash content coal when coal of 8,700 Btu/lb coal is burned as required by the 1978 PSD permit. This is well in excess of the maximum 8% ash content coal that is specified in the 1978 PSD permit. And clearly the 0.66% sulfur content limit exceeds the maximum 0.45% sulfur content coal that is specified in the PSD permit.

The equation that is provided in Condition IV.30 of the draft Independence Title V permit allows coal with an even higher sulfur content than 0.66% to be burned as long as lower ash coal is burned. Specifically, under Condition IV.30, the sulfur content of the coal can exceed 0.66% if the following equation can be met:

$$[((.1 \times S) - 0.03) \times 8700] = [(10 \times (1-0.995) \times A \times 8700 \times (1/C))] <= 662 \text{ lb/hr}$$

where S = sulfur %
A = ash percent, and
C = coal heat value in MMBtu/ton

These increases in sulfur and ash content of the coal burned were authorized in a modification to the Independence Title V permit issued on May 8, 2006. Specifically, in Permit 449-AOP-R4, ADEQ allowed an increase in the allowable sulfur and ash content of the coal that could be burned, and authorized the burning of bituminous coal as well as subbituminous coal at the Independence Station. *See* Draft Independence Title V Renewal Permit (Ex. 1), Section III., at 16. A copy of Permit 449-AOP-R4 is attached as Exhibit 8.

ADEQ improperly authorized these increases in coal ash and sulfur contents. As previously stated, the 1978 PSD permit cannot be revised unless rescinded by EPA or unless a PSD permit modification is issued by ADEQ with a new BACT evaluation. Permit 449-AOP-R4 was not a PSD permit modification, and it did not include a new BACT evaluation. The 1978 PSD permit is still in effect and the Title V permit for Independence must assure compliance with those requirements.

Thus, the Title V renewal permit fails to assure compliance with the applicable requirements of the 1978 PSD permit. EPA must object to the Independence Title V permit because it allows coal to be burned with a sulfur and ash content higher than the 0.45% maximum sulfur content limit and the 8% maximum ash content limit of the 1978 PSD permit.

E. Summary

The Independence Title V permit fails to assure compliance with all applicable requirements of the 1978 PSD permit issued by EPA. Specifically, the Independence Title V permit fails to assure compliance Yith the 15,510 lb/hr limit on SO2 from Independence Units 1 and 2 and the 611 lb/hr limit on TSP from Independence Units 1 and 2 in Condition 3 of the 1978 PSD permit. The Title V permit also fails to include the requirement that the Independence facility comply with the NSPS for Coal Preparation Plants (in 40 C.F.R. Part 60, Subpart Y) as required by Condition 2 of the 1978 PSD permit. Finally, the Independence Title V permit allows coal to be burned in excess of the maximum sulfur content of 0.45% and the maximum ash content of 8% identified in Condition 3 of the 1978 PSD permit. Sierra Club raised each of these issues in its comment letter to ADEQ dated August 9, 2010 at 3-6 (Ex. 3). Because the Independence Title V permit fails to assure compliance with the terms and conditions of the 1978 PSD permit, which is an "applicable requirement" as that term is defined in federal and state operating permit regulations, EPA must object to the Independence Title V permit pursuant to 40 C.F.R. § 70.8(c).

Issue #2: The Administrator Must Object to the Independence Title V Permit Because It Fails to Include PSD Requirements Applicable to the Change in Coal Permitted to be Burned at the Independence Facility.

ADEQ unlawfully modified requirements of EPA's 1978 PSD permit in Title V permit modifications issued prior to the Title V permit renewal for Independence. Specifically, in Permit 449-AOP-R3, ADEQ deleted the requirement that Independence burn subbituminous coal from northeastern Wyoming, among other things.[10] *See* Draft Independence Title V Renewal Permit (Ex. 1), Section III. Permit History, at 16. The permit continued to require the burning of subbituminous coal but did not specify where it came from. *See* Sections II. and IV. of Permit 449-AOP-R3 (Ex. 7). In Permit 449-AOP-R4, ADEQ authorized the burning of bituminous coal as well as subbituminous coal at the Independence station. *See* Draft Independence Title V Renewal Permit (Ex. 1), Section III. Permit History, at 16. ADEQ also increased the allowable sulfur and ash content of the coal that could be burned. *Id.* Thus, the intended effect of these two permitting actions together were to allow EAI flexibility to burn coal other than low sulfur Powder River Basin subbituminous coal from northeastern Wyoming, including higher sulfur and higher ash content coal.

The 1978 PSD permit requires use of coal with sulfur content of no greater than 0.45%,

[10] A copy of Permit 449-AOP-R3 is attached as Exhibit 7.

ash content of no greater than 8%, and heat content of 8700 Btu/lb.[11] These limitations reflect characteristics of low sulfur Powder River Basin sub bituminous coal from northeastern Wyoming. Indeed, subbituminous coal from northeastern Wyoming was the coal planned to be used at the Independence Station, and EPA relied on those plans in evaluating whether the units met BACT for SO2 and TSP and in evaluating ambient air impacts. *See*, e.g., Draft Environmental Impact Statement for Independence Steam Electric Station, Independence County, Arkansas, May 1978, at 3.1-10 to 3.1-11 (regarding alternative coal supplies), 3.1.29 (regarding SO2 control options), 4.2- 1 to 4.2-4 (regarding emission control technology), and 6.3-3 to 6.3-5 (regarding coal contract specifications) (Ex. 13).

ADEQ improperly authorized the change in coal type and the increases in coal ash and sulfur contents. A permitting authority cannot change emission limitations and requirements of a PSD permit, especially not to increase emissions, without issuing a PSD permit modification that complies with all of the PSD permitting requirements. Further, the change in coal type permitted to be burned at Independence should have triggered applicability of PSD as a major modification. ADEQ did not issue a PSD permit modification for these changes, nor did it conduct a new review of BACT for the Independence facility. Further, EAI has in fact been burning coal that is not permitted to be combusted according to the terms of the 1978 PSD Permit.[12] Thus, the Title

---

[11] As discussed in the October 4, 2006 letter from EPA Region VI to ADEQ regarding EAI's Independence and White Bluff Stations, Request for Determination of Prevention of Significant Deterioration Applicability for Lignite Combustion. (Ex. 9).

[12] This is confirmed by through clear admissions in EAI's 2006 FERC Form 1 Annual Reports of Entergy Arkansas Inc. to the Arkansas Public Service Commission (hereinafter "Arkansas Report" in Exhibit 10D to this petition). Specifically, under "Unscheduled Partial Outages," on May 19, 2006, a partial outage was reported as "[t]rying to keep O2 at 3% excess while burning ColoWyo coal." 2006 Arkansas Report at 18.

V Permit for Independence is deficient because it fails to include all applicable requirements regarding the PSD program of the Arkansas SIP. Sierra Club commented on these deficiencies in its August 9, 2010 comment letter to ADEQ (Ex. 3 at 4-9).

A. Background Regarding EPA's 1978 PSD Permit

The 1978 PSD permit for the Independence Station was issued under the EPA's PSD regulations as amended by the Clean Air Act Amendments of 1977.[13] Those amendments included, among other things, the designation of all national parks and national wilderness areas exceeding certain size thresholds that were in existence as of the date of enactment of the Clean Air Act Amendments of 1977 (*i.e.*, August 7, 1977) as mandatory Class I areas and the enactment of requirements to limit the "maximum allowable increases over baseline concentration" (*i.e.*, the "PSD increments"). *See* 42 U.S.C. §§ 7472, 7473, and 7470(4). The amendments also included the requirement for the Federal Land Manager to determine whether a new major source would adversely impact the air quality related values of any Class I area and the ability to certify that a proposed new major source would adversely impact a Class I area. *See* 42 U.S.C. §7475(d).

In addition, a definition of "best available control technology" or "BACT" was enacted that read as follows:

> The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable

[13] *See* Permit PSD-AR-48 at 1 ("Our final determination indicates that you have met the requirements of the prevention of significant deterioration regulations at 40 CFR 52.21, as amended by the Clean Air Act Amendments of 1977...") (Ex. 5).

> for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 7411 or 7412 of this title.

42 U.S.C. § 7479(3) (1977). This definition represented a significant departure from the definition of BACT in EPA's PSD regulations that existed prior to enactment of the 1977 Clean Air Act Amendments, under which BACT was defined as equating with the emissions control required under the applicable New Source Performance Standards. *See* 39 Fed.Reg. 42514 (December 5, 1974) (definition of "best available control technology" at 40 C.F.R. § 52.01(f)).

EPA proposed amendments to its PSD regulations to conform to the 1977 Clean Air Act Amendments on November 3, 1977 (42 Fed.Reg. 57479-88), and stated in that proposal that ". . .the new preconstruction review requirements of Section 165(a) [of the Clean Air Act] would apply to any source which does not obtain a final PSD permit approval before March 1, 1978 (the date the new requirements will be effective)." 42 Fed. Reg. 57479 (November 3, 1977). EPA's justification for making the new PSD requirements effective as quickly as possible was to ensure protection of the PSD increments and because "[t]here is a substantial legal argument. . .that section 165(a) [of the Clean Air Act] was required to be immediately effective because it applies by its terms to sources which commence construction 'after the date of enactment of the 1977 Amendments.'" *Id.* Section 165(a) of the Clean Air Act as amended in 1977 prohibited the construction of any major emitting facility upon which construction commenced after August 7, 1977 unless a permit had been issued for the proposed facility in accordance with the PSD requirements in Part C of the Clean Air Act. *See* 42 U.S.C. § 7475(a).

Although EPA did not promulgate revisions to its PSD regulations to conform to the 1977 Clean Air Act Amendments until June 18, 1978, EPA had previously indicated that it was not revising or extending the March 1, 1978 PSD applicability date[14] and EPA ultimately adopted a March 1, 1978 applicability date for its revised PSD regulations. *See* 43 Fed. Reg. 26389-91,26406 (June 19, 1978)(see 40 C.F.R. § 52.21(i)(2)(i)).

The history of these related statutory and regulatory changes involving the Clean Air Act is relevant to a proper understanding of the Independence 1978 PSD permit.[15] The March 30, 1978 permit for Independence was issued after the enactment of the 1977 Clean Air Act Amendments on March 1, 1978 but before EPA's final promulgation of revisions to its PSD regulations on June 19, 1978. Given that the Independence PSD permit was issued after March 1, 1978 and that the permit itself expressly stated that EPA determined that the requirements of the PSD regulations as amended by the 1977 Clean Air Act Amendments would be met by the Independence facility, EPA almost certainly issued this permit under the proposed revisions to EPA's PSD regulations. This means, among other things, that EPA's BACT determination for Independence was based on a case-by-case analysis of the maximum degree of SO2 and particulate emission reductions that EPA could be achieved at Independence considering the

---

[14] *See, e.g.,* 42 Fed.Reg. 62020 (December 8, 1977).

[15] On August 2, 2010, Sierra Club submitted a Freedom of Information Act ("FOIA") request to EPA asking for all documents relating to the 1978 PSD permit issued for the Independence Station. August 2, 2010 Sierra Club FOIA Request to EPA (Ex. 11). On August 13, 2010, EPA responded by confirming that it had no such responsive documents. August 13, 2010 EPA Response to Sierra Club's FOIA Request (Ex. 12). Because EPA no longer has any of the underlying documents for the March 30, 1978 PSD permit for Independence, an understanding of the statutory and regulatory framework as it existed as of the time of the 1978 Independence PSD permit is critical to understanding the legal underpinnings for this permit.

costs and environment and energy impacts. In other words, EPA's BACT determination was not merely a reflection of the emissions standards of the NSPS as allowed pursuant to 1974 PSD regulations. Instead, consistent with the 1977 Clean Air Act Amendments, the BACT determination set forth in EPA's 1978 PSD permit imposed BACT-derived limits that were more stringent than the applicable NSPS standards.

The EAB has interpreted the requirements of PSD permits as including the control technology upon which BACT is based.[16] In the case of Independence, the SO2 BACT determination was clearly based on the use of low sulfur sub bituminous coal from the Powder River Basin in northeastern Wyoming, with a sulfur content no higher than 0.45%. The BACT determination for particulate matter was also based on use of sub bituminous coal with an ash content no higher than 8%. This is confirmed by a review of the language contained in Condition 3 of the 1978 PSD permit, which states:

> The maximum emission rates of SO2 and TSP shall not exceed 15,510 lbs SO2/hr and 611 lbs TSP/hr ***based on the use of coal with a heat content of 8,700 Btu/lb and a maximum sulfur and ash content of 0.45% and 8%, respectively.***

1978 Independence Permit PSD-AR-48 at 2, Condition 3 (emphasis added) (Ex. 5). Furthermore, as discussed further below, the lb/MMBtu emission limits identified as BACT in Condition 2 of the 1978 PSD permit (*i. e.*, an SO2 limit of 0.93 lb/MMBtu and a TSP limit of 0.04 lb/MMBtu) are entirely consistent with the coal requirements identified in Condition 3 as cited above.

While EPA does not have the underlying documents for the 1978 Independence PSD

[16] *See* In the Matter of CertainTeed Corporation, 1 E.A.D. 743, December 21, 1982 ("an emission limit in a permit cannot be established without also relating it to the specific type of control technology that will be used to achieve the limitation . . . .").

Permit, Sierra Club has obtained other documents which confirm what the basis for the permit conditions in the 1978 PSD permit were. First, the "Summary Report Relative to Permit Application" for ADEQ's initial air permit issued for the Independence Station states that the coal that will be burned at the Independence units will be low sulfur coal from Wyoming. *See* Summary Report Relative to Permit Application for Permit 449-AR-1 at 1 (Ex. 6).

Second, EPA issued a draft environmental impact statement ("EIS") for the Independence Station in May 1978 as part of the issuance of a New Source National Pollutant Discharge Elimination System ("NPDES") permit for wastewater discharge into the White R iver. The draft EIS includes extensive discussion on the coal to be used at the Independence facility, and clearly low sulfur western coal was the choice for meeting SO2 emission standards without the addition of a scrubber. *See* Draft Environmental Impact Statement for Independence Steam Electric Station, Independence County, Arkansas, May 1978, at 3.1-10 to 3.1-1 1, 3.1-29, 4.2-1 to 4.2-4, and 6.3-3 to 6.3-5 (Ex. 13). In particular, the draft EIS states:

> A contract has been negotiated with Antelope Coal Company to obtain low sulfur Wyoming coal with specifications as listed in the following tabulation:

Coal Contract Specifications

Characteristics	Range
Heat Value (Btu/lb)	8200 to 8700 (equilibrium moisture)
Sulfur Content (percent)	0.2 to 0.45 (equilibrium moisture)
Ash Content (percent)	4.0 to 8.0 (equilibrium moisture)
Moisture Content (percent)	25.0 to 30.0 (equilibrium moisture)

Id. at 6.3-4 (Ex. 13).

The EIS goes on to state that in estimating emissions, it was assumed that 10% if the sulfur in the coal would be retained in the bottom ash. With this information, one can readily determine that the 0.93 lb/MMBtu SO2 BACT limit specified in the 1978 PSD permit was specifically based on use of low sulfur coal from the Antelope Coal Company (*i.e.*, subbituminous coal from northeast Wyoming) with a heat value of 8700 Btu/lb and a maximum sulfur content of 0.45%.[17] One can also readily determine that the TSP BACT limit is based on this coal from northeastern Wyoming with a heat value of 8700 Btu/lb and the assumptions derived from page 6.3-5 of the Draft Independence EIS that 20% of the ash will fall out in bottom ash and that the electrostatic precipitator will achieve 99.5% reduction in particulate emissions.[18] Thus, it is clear that EPA's BACT determination was based on the use of subbituminous coal from northeastern Wyoming with a heat value of 8,700 Btu/lb, a maximum sulfur content of 0.45% and a maximum ash content of 8%.

B. ADEQ Unlawfully and Improperly Authorized a Change in the Requirements of the 1978 PSD Permit When It Permitted a Change in the Coal Type and Increases in Maximum Sulfur and Ash Content.

As stated above, ADEQ issued permit modifications in June 2005 (Permit 0449-AOP-R3) and May 2006 (Permit 0449-AOP-R4) which allowed the burning of a different coal type and higher sulfur and ash content coal than allowed under the 1978 PSD permit. *See* Section III. (Permit History) of Draft Independence Title V Renewal Permit at 16-17 (Ex. 1). ADEQ's

---

[17] The SO2 emission rate based on these limitations and assumptions is determined as follows: [(0.0045 lb Sulfur/lb coal) x (0.90 (reflecting 10% of sulfur retained in bottom ash) x (64/32 (molecular weight of SO2/Sulfur))]/[8700 Btu/lb x (1 MMBtu/10^6 Btu)] = 0.93 lb/MMBtu.

[18] The PM emission rate based on these limitations and assumptions is determined as follows: [(0.08 lb Ash/lb coal x 0.80 (reflecting 20% of ash falling out in bottom ash))/(8700 Btu/lb x (1 MMBtu/10^6 Btu))] * (1-0.995) (reflecting control efficiency of ESP) = 0.04 lb/MMBtu.

justification to allow these changes in coal requirements without undergoing a new PSD review was:

> The total permitted emission rate increases associated with the permitting actions included: 1,830.8 tons per year (tpy) PM and 4,599.0 tpy PM10. These increases did not require PSD review because there was no physical modification to the boilers (SN-01 and SN-02) and the original PM PSD limit had not changed with the modification. The PSD limit of 0.04 lb of filterable PM per MMBtu still applied to SN-01 and SN-02.

Id. at 16-17. In its description of the permit history, ADEQ stated that the "actual [BACT] technology requirements were not specified in the [1978 PSD] permit." *Id.* at 15. Based on these statements, it appears that ADEQ believed that so long as the lb/MMBtu BACT limits of Condition 2 of the 1978 PSD permit were met Independence could be permitted to burn any type of coal and consequently removed the requirement from the Independence permit that EAI burn subbituminous coal from northeastern Wyoming based on this erroneous legal position. However, ADEQ's legal conclusion on this issues is incorrect. ADEQ could not lawfully relax requirements that pertain to the BACT determination from the 1978 PSD permit for Independence.[19]

The coal characteristic restrictions in the 1978 PSD permit, which limit Independence to the use of subbituminous coal from northeastern Wyoming with sulfur content no higher than 0.45% and ash content no higher than 8%, serve as the control technology by which Independence was expected to comply with its BACT limits. As such, these restrictions are

---

[19] ADEQ's assertion that PSD review was not required for these changes because there was no "physical modification" to the Independence boilers was also incorrect as a matter of law. A "major modification" which can trigger PSD review can result from ***either*** a "physical change" ***or*** "a change in the method of operation" of a major stationary source. *See* 40 C.F.R. §52.21(b)(2)(i). So the lack of a "physical" modification does not necessarily preclude the application of PSD.

inextricably part of the EPA's BACT determination for the Independence Station reflected in the 1978 PSD permit. And EPA interprets BACT requirements as including not only specific BACT emission limits but also the related control technology upon which a BACT emission limitation is based. *See In the Matter of CertainTeed Corporation*, 1 E.A.D. 743, 1982 WL 43349, at *2-5 (EAB Dec. 21, 1982) ("[T]he 'case-by-case' evaluation of economic costs and energy and environmental impacts that has to be performed as part of a BACT determination is inextricably tied to a specific set of assumptions regarding the type of pollution control technology that will be in place at each facility;" "an emission limitation in a PSD permit cannot be established without also relating it the specific type of control technology that will be used to achieve the limitation;" and the statutory definition of BACT requires a case-by-case analysis of economic, energy and environmental impacts "resulting from a particular control technology. [T]his means that an emission limitation in a PSD permit is keyed to a specific control technology."). Accordingly, ADEQ was prohibited from modifying these BACT requirements applicable to the Independence units without conducting a new BACT analysis and making a new BACT determination. *Id.* at *2 ("Any change in the control technology would require a reevaluation of those [BACT-related] impacts and costs, which, in turn, might necessitate a change in the emission level (lower or higher than the previous one)."). Had EPA known in 1978 that Independence might burn different fuels other than low sulfur subbituminous coal from northeastern Wyoming, EPA's BACT determination would likely have been different. EPA would have almost certainly required a scrubber to remove SO2. That is why EPA does not allow relaxations of BACT determinations (including relaxations of the underlying requirements for BACT determinations) without a new PSD permit including a re-evaluation of BACT.

ADEQ improperly modified these BACT requirements at Independence without issuing a new PSD permit that includes BACT emissions limits, based on currently available technologies and techniques, and that ensures the Independence facility will not cause or contribute to a violation of any national ambient air quality standards (NAAQS) or PSD increment or adversely impact air quality related values in any Class I area. No such PSD permit was issued for the changes in coal type burned or the increases in sulfur and ash content of Permits 445-AOP-R3 and R4. Further, as stated above, the 1978 PSD permit issued by EPA has never been rescinded by EPA and thus it remains in effect.

Had ADEQ issued a revised PSD permit for the fuel changes, a scrubber for SO2 would have been required as BACT. That is because the BACT determination can be no less stringent than the NSPS, *see* 40 C.F.R. §§52.21(b)(12)(1994), as incorporated into APCEC Reg. 19.904(A) and approved by EPA on October 16, 2000 (65 Fed.Reg. 61103). Under the relevant NSPS, after September 18, 1978, no coal-fired electric utility boiler could be constructed or modified without a scrubber for SO2. Thus, the Title V permit for Independence is deficient because it omits applicable PSD requirements which must include, if nothing else, the requirement for the installation of SO2 scrubbers for the Independence boilers and which must include an SO2 BACT emission limit that is no less stringent than the SO2 emission limit imposed by the NSPS, 40 C.F.R. § 60.43Da(i)(3), specifically, 1.4 lb/MWh, 0.15 lb/MMBtu, or a 90% reduction in SO2 emissions on a 30-day rolling average basis. Further, because the BACT limit cannot be any less stringent than the NSPS, that means the PM BACT limit cannot be any less stringent than required under 40 C.F.R. §60.42Da(c) or (d). That is, the PM BACT limit cannot be any less stringent than 0.14 lb/MWh, 0.015 lb/MMBtu, or 0.03 lb/MMBtu and 99.8%

removal. The emission limits and requirements of the Independence Title V permit are unquestionably less stringent than these NSPS requirements. And a proper case-by-case BACT determination would likely result in emission limits more stringent than relevant NSPS limits. Consequently, the Independence Title V permit is deficient because it improperly omits applicable requirements of the PSD program, including, *inter alia*, an adequate BACT determination made for the change in BACT requirements of EPA's 1978 PSD permit that was improperly allowed in the 2005 and 2006 permit revisions.

C. The Switch from Subbituminous Low Sulfur Coal to Bituminous Coal Triggered Applicability of PSD Requirements and the Independence Title V Permit Is Unlawful Because It Was Not Permitted as a Major Modification under the Applicable PSD Requirements.

Even if the fact that ADEQ cannot lawfully relax the requirements of EPA's 1978 PSD permit regarding coal type and sulfur content is ignored, the switch from low sulfur subbituminous coal from northeastern Wyoming to burn a blend of bituminous and subbituminous coal with higher sulfur and ash content than previously allowed was a major modification that should have been subject to PSD permitting requirements.

A major modification is defined as a physical change or a change in the method of operation at an existing major stationary source that would result in a significant emission increase and a significant net emissions increase of any regulated NSR pollutant. *See* 40 C.F.R. §52.21(b)(2)(i) (1994), APCEC Reg. 19.904(A) (adopting EPA's PSD regulations into Arkansas SIP with inconsequential exceptions); approved by EPA at 65 Fed. Reg. 61103 (October 16, 2000). Changing from subbituminous coal from northeastern Wyoming to bituminous and subbituminous coal was a change in the method of operation that would result in a significant net emission increase of SO2, NOx, and PM/PM10/PM2.5 if not other regulated NSR pollutants. While the definition of major modification provides exemptions for changes in fuel, those exemptions do not apply in this case. Specifically, the definition of major modification exempts use of an alternative fuel if the source was capable of accommodating that fuel before January 6, 1975, unless the change to an alternative fuel "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 if the source was approved to use the alternative fuel under any permit issued under 40 CFR 52.21 or 51.166 (*i. e.*, under a PSD permit). *See* 40 C.F.R. § 52.21(b)(2)(e)(1) and (2).[20] The Independence units were not capable of accommodating anything before January 6, 1975 because construction had not yet commenced on the units yet. *See, e.g.*, 1978 PSD Permit at 1 (Independence not approved for construction until 1978). In addition, for the reasons previously discussed, the existing PSD permit issued by EPA in 1978 under 40 CFR 52.21 prohibited the use of coal other than low sulfur coal from northeastern Wyoming as part of the BACT determination and limited the coal to a heat value of 8700 Btu/pound, a maximum sulfur content of 0.45%, and a maximum ash content of 8%. *Id.*, Condition 3, at 2. Additionally, no PSD permit was issued that allowed the burning of alternative fuel subsequent to the 1978 PSD permit.[21] Consequently, the use of alternative coals at the Independence units is not considered

---

[20] *See* 40 C.F.R. § 52.21(b)(2)(iii)(e)(1) (as in effect June 3, 1994), incorporated by reference into APCEC Reg. 19.904(a) which was approved as part of the SIP by EPA in 2000 (*see* 65 Fed. Reg. 61103 (October 16, 2000)).

[21] The Title V permit modifications issued by ADEQ, Permits 445-AOP-R3 and R4, are not PSD permits.

exempt from being considered a major modification.

There is no question that the change in fuel from low sulfur coal from northeastern Wyoming to bituminous and subbituminous coal with a higher sulfur and ash content than allowed under the 1978 PSD permit would result in a significant net emissions increase of SO_2. It is also likely that emissions of particulate matter (PM, PM_{10}, $PM_{2.5}$), and nitrogen oxides (NO_x) would increase as a result of this fuel change to such a degree that PSD review would be required.

In regard to Permit # 0449-AOP-R4, ADEQ improperly determined that PSD would not apply to the change in fuels with its claim that no change in allowable PM emission limits were required. *See* Draft Independence Title V Renewal Permit, Section III. at 16-17 (Ex. 1). Specifically, ADEQ stated that although the permit increased allowable PM emission rates by 1,830.8 tpy and increased allowable PM_{10} emission rates by 4,599.0 tpy, these increases "did not require PSD review because there was no physical modification to the boilers .. and the original PM PSD limit [*i.e.*, 0.04 lb/MMBtu] had not changed with the modification." *Id.* The original PM PSD limit of 0.04 lb/MMBtu only applies to filterable PM. Furthermore, PSD cannot be determined not to apply just because an allowable emission rate did not increase. During this time frame, PSD applicability was required to be based on actual emissions before the modification to actual or allowable emissions after the modification as those terms were defined in the EPA-approved Arkansas SIP. *See* 40 C.F.R. §§ 52.21(b)(3)(i), 52.21(b)(21)(v), 52.21(b)(38)(v); APCEC Reg. 19.904(a); *see* 65 Fed. Reg. 61103 (October 16, 2000)). And in this case, allowable emissions of total PM and PM_{10} did increase. *See* Draft Independence Renewal Permit at 16 (Ex. 1). So the fact that ADEQ did not change the 0.04 lb/MMBtu filterable PM limit does not ensure no significant emission increase of total PM, PM_{10}, or $PM_{2.5}$ (*i.e.*, filterable plus condensible PM). In fact, because the Permit 0449-AOP-R4 authorizing the fuel change to bituminous coal with higher sulfur and ash content allowed for an increase in total PM emissions of 915.4 tpy per boiler and an increase in total PM_{10} emissions of 2,299.5 tpy per boiler[22], this permit allowed for much more than a significant increase of both PM and PM_{10} at each boiler. Further, the 2006 permit authorizing the coal changes also allowed for a significant increase in $PM_{2.5}$.[23] Thus, there is no question that the 2006 permit change and fuel changes should have triggered PSD for PM, PM_{10}, and $PM_{2.5}$ at each boiler.

As note *supra*, ADEQ made an additional legal error in ignoring the fact that the definition of "major modification" is not defined solely as a "physical change" but may also include "a change in the method of operation." *See* 40 C.F.R. §§ 52.21(b)(2)(i). A change in the type of fuel burned, especially a change from the fuel mandated in pre-existing permits, is a change in the method of operation which may trigger PSD review.

Under the SIP-approved Arkansas PSD rules at the time of these permit changes, post-change actual emissions at an electric utility steam generating unit like the Independence units would be determined as follows:

> actual emissions of the unit following the physical or operational change shall equal the representative actual annual emissions of the unit, provided 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,

---

[22] Per discussion of permit change in Draft Independence Title V Permit 0449-AOP-R7 at 16 (Ex. 1).

[23] At the time of this permit change, EPA had not yet promulgated significance levels for $PM_{2.5}$. Because it was a regulated pollutant under the Clean Air Act, *any increase* was significant. *See* 40 C.F.R. § 52.21(b)(23)(ii).

> information demonstrating that the physical or operational change did not result in an emissions increase. . . .

See 40 C.F.R. § 52.21(b)(21)(v); 40 C.F.R. § 52.21(b)(3)(i) (1994), incorporated by reference into APCEC Reg. 19.904(A) and approved by EPA as part of the SIP in 2000 (*see* 65 Fed. Reg. 61103 (October 16, 2000)).

Representative actual annual emissions are in turn defined as:

> . . .the average rate, in tons per year, at which the source is projected to emit a pollutant for the two year period after a physical change or change in the method of operation of a unit, (or a different consecutive two year period within 10 years after that change, where the Administrator determines that such period is more representative of normal source operations), considering the effect any such change will have on increasing or decreasing the hourly emissions rate and on projected capacity utilization. In projecting future emissions the Administrator shall:
>
> (i) Consider all relevant information, including but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under title IV of the Clean Air Act. . . .

See 40 C.F.R. § 52.21(b)(38)(v), § 52.21(b)(3)(i) (1994), incorporated by reference into APCEC Reg. 19.904(A) and approved by EPA as part of the SIP in 2000 (*see* 65 Fed. Reg. 61103 (October 16, 2000)).

If the source owner fails to report every year for five years after the physical or operational change, post-change emissions must be based on the potential to emit of the units. *See* 40 C.F.R. § 52.21(b)(21)(v) (1994). Sierra Club's research has revealed no evidence that EAI has reported emissions at Independence following the subject fuel changes. Because EAI did not report emissions for five years following the fuel changes, applicability to PSD for the fuel changes must be based on a comparison of actual emissions to potential emissions post-fuel switch.

As explained below, when analyzed in accordance with the applicable SIP-approved PSD regulations, emissions of SO2 would increase with a change to a higher sulfur coal as allowed in the 2006 permit, and emissions of NOx would also increase with the switch from sub bituminous to bituminous coal because of less fuel bound nitrogen in subbituminous coal.[24] Actual emissions of SO2 and NOx before the change can be determined from emissions data available on EPA's Clean Air Markets Database. According to the regulations approved into the SIP at the time of these permit changes, actual emissions before the modification are based on the average of the two years prior to the change. *See* 40 C.F.R. §52.2 1 (b)(2 1)(ii) (1994), APCEC Reg. 19.904(A), approved by EPA at 65 Fed. Reg. 61 1 03 (October 16, 2000). At the time of the fuel changes at Independence, EPA policy also allowed electric utility boilers to use any two year period of emissions out of the preceding five years of emissions as reflective of normal source operations before the modification. *See* 57 Fed.Reg. 32323 (July 21, 1992). However, the strict language of the PSD rules in effect in Arkansas at the time of the fuel change only allowed the use of a different two year period if the permitting authority determined that a different period other than the two years preceding a modification was more representative of normal source operations. Sierra Club used both the two years prior to the fuel change that was permitted and occurred in 2006 and also the high two years of emissions out of the five years prior to the 2006 fuel change to determine baseline emissions. *See* Table 1 *infra*. However, under the Arkansas

---

[24] EPA's AP-42 identifies a higher NOx emission rate for bituminous coal-fired dry bottom NSPS boilers such as the Independence boilers as compared to those same boilers fueled with subbituminous coal. Specifically, the NOx emission factor for bituminous coal-fired units is 10 lb/ton of coal burned, as compared to the 7.2 lb/ton NOx emission factor for subbituminous coal-fired boilers. *See* AP-42, Table 1.1-3.

SIP in effect at the time of these fuel changes, the rules do not allow for the use of the high two years out of five years for determining the baseline emissions due to the fuel change because the permitting authority has not determined that a different two year period is more representative of normal source operations. *See* 40 C.F.R. §52.21(b)(21)(ii) (1994), as incorporated by reference into APCEC Reg. 19.904(A) and approved by EPA into the SIP in 2000 (65 Fed. Reg. 61103 (October 16, 2000)).

EAI began burning bituminous coal at the Independence unit by May 2006 if not before.[25] This was the same time that Permit 0449-AOP-R4 was issued authorizing the fuel change.[26] For this reason, the 2004-2005 period was used as the baseline period for the fuel change and emissions between 2001 and 2005 were evaluated to determine the highest consecutive two years of emissions out of the preceding five years before the modification.

To calculate the potential to emit SO2 after the fuel change, it was determined that the SO2 limit contained in the Title V permit of 0.93 lb/MMBtu[27] was more limiting than the SO2 emission rate which could be produced when the Independence Station combusts the 0.66% or higher sulfur content coal which is now allowed to be burned at Independence pursuant to Permit 0449-AOP-R4, Section IV., Condition 30 (Ex. 8). Coal with a sulfur content of 0.66% and a heat

---

[25] This is made clear by statements in EAI's 2006 FERC Form 1 Annual Reports of Entergy Arkansas Inc. to the Arkansas Public Service Commission (hereinafter "Arkansas Report" (Ex. 10D). Specifically, under "Unscheduled Partial Outages," on May 19, 2006, a partial outage was reported as "[t]rying to keep O2 at 3% excess while burning ColoWyo coal." 2006 Arkansas Report at 18. ColoWyo coal is a western bituminous coal from Colorado.

[26] This permit was issued on May 8, 2006. *See* Draft Independence Title V Permit 0449-AOP-R7 at 16 (Ex. 1).

[27] *See* Draft Independence Title V Permit 0449-AOP-R7 at 23 (Ex. 1).

value of 8, 700 Btu/lb would have an uncontrolled SO2 emission rate from the boiler of 1.44 lb/ MMBtu based on EPA's AP-42 emission factors for bituminous coal. Even if a much higher heat value was assumed for the coal, such as 12,000 Btu/lb, the uncontrolled SO2 emission rate from the boiler with 0.66% ash coal would be 1.045 lb/MMBtu, which still exceeds the allowable 0.93 lb/MMBtu SO2 limit. Consequently, the tons per year allowable SO2 emission rate of Permit 0449-AOP-R4 -- 35,438 tons per year per boiler -- reflects the Independence unit's potential to emit SO2. *See* Permit #0449-AOP-R4 at 20 (Ex. 8).

Likewise, the potential to emit NOx from the Independence units is also based on the tons per year allowable emission rate of Permit 0449-AOP-R4, or 26,674 tons per year per boiler. *Id.* And the end result of this analysis is the same as for SO2; namely, that the comparison of actual to potential emissions of NOx due to the fuel change reflected in Permit 0449-AOP-R4 would produce a significant net emission increase of NOx.

In addition to evaluating PSD applicability on an actual to potential basis, which, according to the applicable SIP-approved regulations, is plainly the appropriate methodology for evaluating an emission increase under the circumstances because EAI failed to report emissions for five years following the fuel switch, one can also evaluate the actual emissions that occurred after the fuel switch from the emissions data reported to EPA's Clean Air Markets Database.[28]

As Table 1 below shows, there would be a significant net emission increase[29] of both SO2

---

[28] The actual emissions data is provided in Table 1.

[29] Because there are no contemporaneous and creditable emission reductions that can be taken into account in evaluating the net emissions increase of the fuel change at the Independence units, the net emissions increase will be at least as high as the increase in emissions from the fuel change itself. Net emissions increase could be higher if there were contemporaneous and creditable emissions increases that need to be added in. *See* 40 C.F.R.

and NOx at each boiler when the fuel change is evaluated on an actual to potential emissions basis, as would be required if EAI did not report emissions for each of the five years after the permitted fuel change.

§52.21(b)(3) (1994); incorporated by reference into APCEC Reg. 19.904(a) as incorporated into the SIP by EPA (*see* 65 Fed. Reg. 61103 (October 16, 2000)).

Table 1: *Pre- and Post-Change Emissions at Independence Station for the Change from NE Wyoming Coal to Subbituminous and Bituminous Coal with Higher Sulfur and Ash Content.*

Unit No.	Pre/Post Yrs	SO2 Emissions	NOx Emissions	Significant SO2 NOx Increase?	Significant Increase?
1	2004-2005 Baseline	11,384 tpy	7,069 tpy		
	High 2 out of 5 Baseline	11,552 tpy	7,617 tpy		
	Potential to emit	35,428 tpy	26,674 tpy	Actual to PTE: > **40 tpy** Pre-change to post-change actual: **> 40 tpy all post change years, regardless of baseline used.**	Actual to PTE: > **40 tpy** Pre-change to post-change actual: **> 40 tpy in 2007 and 2008, regardless of baseline used**
	2007 emissions	14,682 tons	8,740 tons		
	2008 emissions	13,763 tons	7,981 tons		
	2009 emissions	12,254 tons	6,610 tons		
2	2004-2005	11,592 tpy	7,277 tpy		
	High 2 out of 5	12,262 tpy	9,820 tpy		
	Potential to emit	35,428 tpy	26,674 tpy	Actual to PTE: > **40 tpy** Pre-change to post-change actual: **> 40 tpy in all post change years, regardless of baseline used.**	Actual to PTE: > **40 tpy** Pre-change to post-change actual: **> 40 tpy in 2007 and 2009 with 2004-2005 baseline.**
	2007 emissions	14,857 tons	8,613 tpy		
	2008 emissions	12,685 tons	7,142 tpy		
	2009 emissions	15,171 tons	7,728 tpy		

Note: Actual emissions data is based on data obtained from EPA's Clean Air Markets Database at http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard. Potential to emit is based on limitations in Permit #0449-AOP-R4 (Ex. 8).

Furthermore, actual emissions of SO2 increased more than 40 tons above baseline emissions (regardless of whether baseline emissions are based on 2004-2005 emissions or based on the high two years out of five) in each year following the 2006 permitted change in fuels. For

Unit 1, the SO_2 actual emission increase ranged from 702 tons to 3,298 tons. For Unit 2, the SO_2 actual emissions increase ranged from 423 tons to 2,909 tons.

Similarly, the actual emission increase of NOx at Unit 1 was greater than the 40 tons per year significance level in 2007 and 2008, regardless of which baseline is used. The NOx actual emission increase ranged from 364 tons to 1,671 tons. At Unit 2, the 2007 and 2009 actual emissions of NOx increased significantly above the 2004-2005 baseline, ranging from 451 tons to 1,336 tons above that baseline. However, the actual emissions of NOx did not increase above a significance level when assessed against a high two out of five baseline. This is of no moment, however, because there is no record that any permitting authority previously determined that a different baseline other than the two years preceding the 2006 permitted change in fuels was more representative of normal source operations. And as a consequence, EAI is not entitled to avail itself to the high two out of five baseline.[30]

EAI also would have projected significant emission increases of SO_2, PM/PM10/PM2.5, and NOx based on representative actual annual emissions of these pollutants.

Emissions of SO_2

---

[30] Although EPA had allowed electric utility boilers to choose any two consecutive years out of the five years preceding a modification in determining baseline emissions, the plain language of the Arkansas SIP as in effect at the time of the 2006 permit change required baseline to be based on the two years before the modification "unless the permitting authority determines that a different two year period is more representative of normal source operations." *See* 40 C.F.R. § 52.21(b)(21)(ii), incorporated by reference into APCEC Reg. 19.904(a), incorporated into the SIP by EPA (*see* 65 Fed. Reg. 61103 (October 16, 2000)). There is no information in the record which indicates that ADEQ determined a different two year period to be more representative of normal source operation for the 2006 permitted fuel change and, therefore, EIA is not permitted to rely on a high two years out of five to avoid the application of PSD for NOx emissions to Independence Unit 2.

and particulate matter are directly linked to the sulfur and ash content of the coal burned.[31] It is therefore inconceivable that EAI could have projected anything less than a significant emission increase of SO2 and PM/PM10/PM2.5, with these increases in allowable sulfur and ash content of the coal that can be burned at the Independence units. Indeed, the fact that the final permit allows for significant increases in allowable emissions of these pollutants, as previously discussed, appears to all but confirm that EAI would have projected significant increases in PM, PM10 and PM2.5 emissions from the permitted fuel change in question.

With respect to SO2 and NOx, it would not take much of an increase in the emission rates of these pollutants to equate to a significant increase of SO2 and NOx at each Independence unit. If one simply assumes the units will have the same heat input in the future as the two year average heat input before the permitted fuel switch, it would only take a projected 0.0014 lb/MMBtu increase in the annual average SO2 or NOx emission rate to exceed a significant emission increase of 40 tons per year. In fact, a review of annual average SO2 and NOx emission rates (in lb/MMBtu) shows that emission rates have increased that much. For SO2, the annual average SO2 emission rate in 2004-2005 was 0.39 lb/MMBtu at Unit 1, and the SO2 rate actually increased to 0.44 to 0.46 lb/MMBtu in the years after the permitted fuel changes.[32] Unit 2 saw a similar jump in annual average SO2 emission rate, from 0.40 lb/MMBtu in 2004-2005 to 0.44 to 0.47 lb/MMBtu in the years after the permitted fuel changes. The Unit 1 NOx emission rate averaged 0.24 lb/MMBtu in 2004-2005, and increased to 0.25 to 0.26 lb/MMBtu in the years

---

[31] *See* EPA's AP-42 Emission Factors for Bituminous and Subbituminous Coal Combustion, Tables 1.1-3 and 1.1-4.

[32] This is based on annual average SO2 emission rates calculated from Independence emission data in EPA's Clean Air Markets Database.

after the permitted fuel switch. The Unit 2 NOx emission rate in 2005 was 0.245 lb/MMBtu in 2005, and it increased to 0.25 lb/MMBtu in 2007 and 2008.[33] Thus, because the use of bituminous coal and higher sulfur coal would result in higher emission rates for SO2 and NOx than when lower sulfur subbituminous coal was burned (as the actual emissions data verifies), had EAI projected representative actual annual emissions, it clearly would have projected significant net emission increases of SO2 and NOx.

ADEQ improperly authorized EAI to change from burning subbituminous coal from northeastern Wyoming to subbituminous and bituminous coal with higher sulfur and ash content than allowed in the 1978 PSD permit for the Independence facility. This change in fuel and increase in sulfur and ash contents should have been thoroughly reviewed for PSD applicability. Unfortunately, it appears that did not happen. No PSD permit was issued for the changes in coal type burned or the increases in sulfur and ash content of Permits 445-AOP-R3 and R4 and, to the extent that any PSD applicability analysis has been performed for these actions, that analysis was inadequate or otherwise erroneous.

If a PSD review of these actions had been performed properly, ADEQ and EAI would have recognized that the proposed fuel change would trigger PSD for PM, PM10, PM2.5, SO2, and NOx for the reasons described above. Such an analysis would have alerted ADEQ and EAI to the fact that a PSD permit, including BACT emissions limits based on currently available technologies and techniques, was required for this major modification. And any such PSD permit issued would have been required to ensure that the Independence Station did not cause or

[33] The 2004 NOx rate was higher at 0.26 lb/MMBtu, so there was not an increase in NOx rate at Unit 2 based on a comparison to the average NOx rate over 2004-2005.

contribute to a violation of any national ambient air quality standards (NAAQS) or PSD increment or adversely impact air quality related values in any Class I area. *See* 40 C.F.R. §§52.21(k), (o), and (p) (1994), incorporated by reference into APCEC Reg. 19.904(A), approved as part of the SIP by EPA in 2000 (65 Fed. Reg. 61103 (October 16, 2000)).

Specifically with regard to SO2 emissions, had ADEQ issued a revised PSD permit covering these permitting actions, a scrubber for SO2 would have been required as BACT. That is because the BACT determination can be no less stringent than the NSPS, 42 U.S .C. § 7479(3), and after September 18,1978, no coal-fired electric utility boiler could be constructed modified without a scrubber for SO2 – a device which is necessary to meet the NSPS SO2 limitation imposed on new NSPS sources at that time. *See* 40 C.F.R. § 60.43Da(i)(3) . Thus, the Title V permit for Independence is deficient because it omits applicable PSD requirements which must include, if nothing else, the requirement for the installation of SO2 scrubbers at the Independence boilers and impose an emission limit no less stringent than that required in 40 C.F.R. § 60.43Da(i)(3) – specifically, 1.4 lb/MWh, 0. 15 lb/MMBtu, or a 90% reduction in SO2 emissions on a 30-day rolling average basis.

The Title V permit is also deficient because it does not include emission limits reflective of BACT for PM/PM10/PM2.5 or NOx. Because the BACT limit cannot be any less stringent than the NSPS, that means the PM BACT limit cannot be any less stringent than required under 40 C.F.R. §60.42Da(c) or (d). That is, the PM BACT limit cannot be any less stringent than 0.14 lb/MWh, 0.015 lb/MMBtu, or 0.03 lb/MMBtu and 99.8% removal. And the NOx BACT limit cannot be any less stringent than the NSPS limits in 40 C.F.R. §60.44Da(e)(3). That is, the NOx BACT limit cannot be any less stringent than 1.4 lb/MWh or 0.15 lb/MMBtu, as measured on a

30 day rolling average. The emission limits and requirements of the Independence Title V permit are unquestionably less stringent than these NSPS requirements. And a proper case-by-case BACT determination would likely result in emission limits more stringent than relevant NSPS limits. Consequently, the Independence Title V permit is deficient because it improperly omits applicable requirements of the PSD program, including, *inter alia*, an adequate BACT determination made for the 2006 permitted change in fuels.

D. Summary

In summary, the draft Independence Title V Permit is deficient because it omits PSD requirements including BACT requirements and limits applicable to the change in coal that occurred at the Independence units beginning in 2006. The use of subbituminous coal from the Powder River Basin of northeastern Wyoming with sulfur content no higher than 0.45% and ash content no higher than 8% was clearly part of the SO2 and TSP BACT determination for the 1978 PSD permit issued by EPA. Permitting authorities cannot relax BACT requirements without a new evaluation of BACT as of today. Further, the change in the permitted fuel to be burned at the Independence units triggered PSD requirements as a major modification for SO2, PM/PM10, PM2.5, and NOx if not other regulated NSR pollutants. The draft Title V permit for Independence omits applicable PSD permitting requirements including BACT emission limits based on a current case-by-case analysis which would, without question, be more stringent than the requirements in the draft Title V permit for Independence. Therefore, EPA must object to the Independence Title V permit because it fails to assure compliance with all applicable requirements of the Clean Air Act including the PSD permitting requirements of the Arkansas SIP.

Issue # 3: The Administrator Must Object to the Independence Title V Permit Because It Fails to Include PSD Requirements Applicable to Replacement of the Economizer at Independence Unit 2.

On September 19, 2008, EAI submitted a letter to ADEQ providing notification of the replacement of the economizer at Independence Unit 2. September 19, 2008 Letter from Entergy's M. Bowles to ADEQ's T. Rheaume at 1 (Ex. 1 to Sierra Club's August 9, 2010 comment letter to ADEQ (in Ex. 3 to this petition). EAI indicated that there was not a "reasonable possibility" that a significant emissions increase would occur as a result of these projects and therefore, EAI determined the provisions of 40 C.F.R. § 52.21®)(6) do not apply. At the time that this letter was submitted to ADEQ, it does not appear that EAI provided emissions calculations to demonstrate there was no reasonable possibility that a significant emissions increase would occur. *Id.* A review of available information indicates that EAI should have projected that a significant emissions increase and a significant net emissions increase would occur as a result of the economizer replacement at Unit 2. Indeed, the Unit 2 economizer replacement was a major modification that triggered PSD applicability for SO2 and possibly other regulated NSR pollutants, but ADEQ did not issue any PSD permit for this major modification. Thus, the Title V permit is deficient because it omits PSD requirements including BACT emission limits applicable to the replacement of the economizer at Unit 2. Sierra Club raised this issue in its August 9, 2010 comment letter to ADEQ on the draft Independence Title V renewal permit. *See* 8/9/10 Sierra Club Comment Letter at 9-12 (Ex. 3).

On approximately October 15, 2010, Sierra Club was provided with a set of documents from ADEQ in response to a state freedom of information request which included EAI's responses to Sierra Club's comments on the draft Independence Title V permit. On October 18, 2010, it was first discovered that EAI's response to Sierra Club's comments included emission calculations for the subject economizer projects from EIA. *See* Independence Steam Electric Station ("ISES") Exhibit C (Ex. 14B). It appears that these calculations were not submitted to ADEQ until approximately October 7, 2010, when EAI provided its response to Sierra Club's comments on the draft Independence Title V permit. October 7, 2010 EAI Response to Sierra Club's Comments on Independence's Title V Permit and Emission Calculations (Ex. 14A). And thus far, ADEQ has not relied on these calculations in any manner or indicated it has any intention to do so in the future. At this juncture, Sierra Club is analyzing EAI's recently produced emissions projections and will endeavor to address them in this petition to extent that it is practicable to do so and relevant to the issue in question. However, particularly since ADEQ has not submitted its final response to Sierra Club's comments on the draft Title V permit, much less issued a proposed a final Title V permit, Sierra Club expressly reserves the right to supplement this petition to address EAI's emission projection calculations in more detail, as well as other documents and issues that may arise or become more prominent as the permitting process at ADEQ goes forward.

A. Background

The PSD regulations of the approved Arkansas State Implementation Plan (APCEC Reg. 19, Chapter 9), which for the most part incorporate by reference the provisions of 40 C.F.R. § 52.21 as in effect on July 23, 2004, impose the obligation on the owner or operator of a source to notify the ADEQ and provide emission calculations prior to undertaking a project, as well as the duty to notify the permitting authority of emissions changes ***after*** undertaking a project, if there is a "reasonable possibility" that the project will result in a significant emissions increase. *See* 40

C.F.R. § 52.21®)(6). EAI notified ADEQ of its intent to replace the economizer at Independence Unit 2 in a September 19, 2008 letter to ADEQ. September 19, 2008 Letter from Entergy's M. Bowles to ADEQ's T. Rheaume at 1 (Ex. 1 to Ex. 3 of this petition). In that letter, EAI stated:

> Entergy has performed the required emission evaluation comparing past actual emissions to future projected "post project" emissions. This emissions evaluation demonstrated that there was not a "reasonable possibility" that a significant emission increase would occur as a result of this project, therefore we have determined that the provisions of 40 CFR 52.21®)(6) <u>do not</u> apply.

Id. Presumably because EAI contended that there was no reasonable possibility that a significant emission increase would occur as a result of the economizer replacement at Unit 2, it did appear to provide ADEQ with the past actual to post project emission calculations. It also did not report annual emissions after replacement of the economizer project. As previously stated, EAI submitted its emission calculations for the economizer replacement at Unit 2 in an October 7, 2010 submittal to ADEQ, in which EAI provided responses to Sierra Club's comments on the draft Title V renewal permit for Independence. (Ex. 14B). And as will be discussed below, publicly available information makes clear that there was no legitimate reason not to expect the replacement of the economizer at Independence Unit 2 to result in a significant emission increase of at least SO2.

PSD applicability analysis involves an assessment of emissions increases under the applicable rules. Under APCEC Reg. 19.904 and the federal PSD rules as in effect at the time of the Unit 2 economizer replacement, there is a two-step process for determining applicability to PSD permitting requirements as a major modification. Specifically, there must be both a "significant emissions increase" and a "significant net emission increase" of a regulated NSR pollutant in order for a project to be considered a "major modification" subject to PSD permitting requirements APCEC Reg. 19.904; 40 C.F.R. § 52.21(a)(2)(iv)(a) (2005).

In determining whether a significant emission increase has occurred in Step 1 of the PSD applicability process, one subtracts baseline actual emissions from future projected actual emissions. 40 C.F.R. § 52.21(a)(2)(iv)(c). "Baseline actual emissions" is defined in the PSD regulations in pertinent part as:

> the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with paragraphs (b)(48)(i) through (iv) of this section.
>
> (i) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation.
>
> . . .
>
> (b) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above any emission limitation that was legally enforceable during the consecutive 24-month period.

40 C.F.R. § 52.21(b)(48).

The term "projected actual emissions" is defined in the federal PSD regulations incorporated into the Arkansas SIP as follows:

> (i) *Projected actual emissions* means the *maximum annual rate*, in tons per year, *at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project*, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.

> (ii) In determining the projected actual emissions under paragraph (b)(41)(i) of this section (before beginning actual construction), the owner or operator of the major stationary source:
>
> (a) 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
>
> (b) Shall include fugitive emissions to the extent quantifiable and emissions associated with startups, shutdowns, and malfunctions; and
>
> (c) Shall exclude, in calculating any increase in emissions that results from he 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) (2005) (emphasis added).

It must be noted that if there are other independent projects at a unit occurring at or near the same time as a project being evaluated that would decrease emissions, such as a pollution reduction project, one does not consider the effect of those projects on projecting actual emissions in determining whether a significant emission increase would occur as a result of a project. Only emission increases are evaluated in the Step 1 evaluation of whether a project will result in a significant emission increase of any regulated NSR pollutant. *See* 40 C.F.R. §52.21(a)(2)(iv)(c), (d) and (f); March 30, 2010 Memorandum from B. Finazzo, EPA Region 2, Director of Division of Environmental Planning and Protection, to K. Antoine, Environmental Director, HOVENSA, L.L.C. at 3-4 (Ex. 15). Such emission decreases can be taken into account when determining whether a significant net emissions increase would occur, but only if such emission decreases are contemporaneous and are otherwise creditable.

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" includes limitations on the emission reductions can be credited including that any emission reductions must be made enforceable as a practical matter by the time construction commences on the project. 40 C.F.R. § 52.21(b)(3), incorporated by reference into the Arkansas SIP at APCEC Reg. 19.904(A).

B. The Independence Unit 2 Economizer Replacement Should Have Been Projected to Result in a Significant Emission Increase and a Significant Net Emissions Increase for at least SO2 if not Other Regulated NSR Pollutants

The publicly available information reviewed to date by Sierra Club makes clear that the replacement of the economizer at Independence Unit 2 should have been projected to result in a significant emission increase and a significant net emissions increase of at least SO2 if not other regulated NSR pollutants.[34] also

[34] Although it has adequately demonstrated with the available information that the draft Independence Title V permit is legally inadequate and that EPA is obligated under the circumstances to issue an objection to that permit, there is a large amount of relevant information and data to the issues presented here which have not been made available to the public. For instance, Sierra Club has not been able to obtain a copy of relevant GADS data for the Independence Plant or the information which EAI submitted to ADEQ in attachment D to EAI's October 7, 2010 response to Sierra Club's comments on the draft Independence Title V permit. Furthermore, the underlying data, formulas/calculations and assumptions supporting EAI's emissions calculations has not been made publicly available. And very little factual information relevant to the routine maintenance issue has been produced to the public. Without access to these types of relevant information, it is extraordinarily difficult for the public to evaluate any of the claims made by EAI or conclusions drawn by ADEQ about whether the draft Title V permit comports with the applicable legal requirements. Sierra Club would implore EPA to rectify this situation by making sure that all the information relevant to the issues raised by this petition is made available to all members of the public. Only by doing so can EPA ensure that the public has actually had a fair opportunity to evaluate the legal issues relating to the Independence Plant.

On September 19, 2008, EAI notified ADEQ that it intended to replace the economizer section of the Unit 2 boiler. September 19, 2008 Letter from Entergy's M. Bowles to ADEQ's T. Rheaume at 1 (Ex. 1 to Ex. 3 of this petition). EAI commenced construction on the economizer replacement project for Independence Unit 2 sometime after September 19, 2008 and by November 3, 2008 that work was completed and Unit 2 commenced operations. November 24, 2008 Letter from Entergy's M. Bowles to ADEQ's T. Rheaume at 1 (Ex. 3 to Ex. 3 of this petition).

Replacement of the economizer at a coal-fired electric utility steam generating unit is a significant project that may take as long as a month or two to complete and represents a very significant capital expenditure. Such equipment is replaced when problems are occurring such as tube leaks that cause forced outages and/or design flaws that are causing derates. EAI reports information on such scheduled and forced outages to the Arkansas Public Service Commission (PSC).[35]

As reflected in the FERC Form 1 Annual Reports of Entergy Arkansas Inc. to the Arkansas Public Service Commission (*i.e.*, "Arkansas Reports," Exs. 10A - 10F to this Petition), during any 24 month period within the last five years preceding the Unit 2 economizer replacement project, Unit 2 lost significant numbers of hours due to forced outages and/or deratings associated with the Unit 2 economizer, and those outages and deratings would have

[35] These are available on the Arkansas Public Service Commission internet site and are referred to as "Arkansas Reports." *See* http://www.apscservices.info/AnnualReport.asp. Copies of the Arkansas Reports for the five years preceding the 2008 economizer replacement at Unit 2 are attached as Exhibits 10A-10F. It is not clear whether the information included in these reports is as comprehensive as is reported in Generating Availability Data System (GADS) reports for each electric utility unit.

been eliminated as a result of the 2008 economizer replacement project. Specifically, during any 24 month baseline period of the five year immediately prior to when the economizer was replaced in September 2008, EAI lost as few as 34 hours on average per year to as many as 198 hours on average per year due to forced outages related to the economizer. The median number of lost hours on average per year during any potential baseline period was 47 hours. EAI also lost MW-hours due to deratings related to the economizer, as is reflected in the FERC Form 1 Reports under "Unscheduled Partial Outages." Sierra Club did not tally up the deratings. Table 2 below shows the forced complete outages due to the economizer at Independence Unit 2, obtained from the Arkansas Reports to the PSC (Exs. 10A - 10F).

Table 2: Forced Outages at Independence Unit 2 Due to Economizer During Five Years Before Economizer Was Replaced (September 2003 Through August 2008)

Date of "Unscheduled Complete Outage"	**Hours of Outage Due to Economizer**	**Documentation for Outage**
10/18 - 10/20/2003	52.8	2003 EAI Arkansas Report at Supp. E-6A (Ex. 10A).
10/27 - 10/30/2003	67.2	2003 EAI Arkansas Report at Supp. E-6A (Ex. 10A).
4/17 - 4/19/2004	47.4	2004 EAI Arkansas Report at Supp. E-6 (Ex. 10B).
8/29 - 8/31/2004	61.7	2004 EAI Arkansas Report at Supp. E-6A (Ex. 10B).
9/3 - 9/5/2004	47.5	2004 EAI Arkansas Report at Supp. E-6A (Ex. 10B).
5/11 - 5/13/2005	51.32	2005 EAI Arkansas Report at Supp. E-6 (Ex. 10C).
5/15 - 5/17/2005	34.45	2005 EAI Arkansas Report at Supp. E-6 (Ex. 10C).

9/14 - 9/16/2005	34.62	2005 EAI Arkansas Report at Supp. E-6 (Ex. 10C).
6/7 - 6/10/2006	68.38	2006 EAI Arkansas Report at Supp. E-6 (Ex. 10D).
1/4 - 1/8/2008	56.48	2008 EAI Arkansas Report at Supp. E-6 (Ex. 10F).
3/17 - 3/19/2008	59.08	2008 EAI Arkansas Report at Supp. E-6 (Ex. 10F).
7/29 - 7/30/08	43.72	2008 EAI Arkansas Report at Supp. E-6 (Ex. 10F).

In the emissions calculations that EAI provided to ADEQ in an October 7, 2010 submittal, EAI relied on calendar years 2006 to 2007 as the 24 month period for baseline actual emissions. *See* ISIS Exhibit C to EAI's October 7, 2010 letter to ADEQ, Attachment to September 19, 2008 EAI letter to ADEQ Entitled ISIS #2 Economizer - NSR Actual to Future Projected Actual Calculation (Ex. 14B). Based on the forced outage data in the FERC Form 1 Reports for Independence Unit 2, during the 24 month period from January 2006 to December 2007, Independence Unit 2 experienced 34 hours per year on average of lost operating time due to forced outages related to the economizer. When the economizer was replaced, the unit could be expected to regain at least 34 hours of operation per year, as well as not suffer the deratings that Unit 2 suffered due to the economizer during EIA's 2006-2007 baseline period. Those additional hours of operation should have been projected to result in an increase in emissions.

Sierra Club has briefly reviewed EAI's projection of actual emissions for the five years after the economizer replacement. EAI projected that emissions of every regulated NSR pollutant would decrease from the 2006-2007 baseline emissions. *Id.* It appears that EAI arrived at these projected actual emission numbers based on the assumption that there would be less electricity generated during the five years after replacement of the economizer than was generated during the baseline period. Specifically, EAI projected the annual electricity production to be anywhere from 4,725 GW-hrs per year to 5,451 GW-hrs per year. *See* ISES Exhibit C to EAI's October 7, 2010 letter to ADEQ, Attachment to September 19, 2008 EAI letter to ADEQ Entitled ISES2 Heat Rate Improvement Study (Ex. 14B). Yet, during the 2006-2007 baseline period, Independence Unit 2 produced 5,999 gross GW-hrs on average per year.[36] It is inconceivable how EAI could have projected such a significant decrease in GW-hrs produced in the five years after the replacement of the economizer at Unit 2. While EAI also took into account a projected 0.97% improvement in the heat rate after the replacement of the economizer, that does not explain the significant decrease in projected electricity production at Unit 2 in EAI's projected future actual emissions analysis. Indeed, if the heat rate decreased, the unit would be less expensive to run and it would likely be dispatched more often and thus produce more electricity and emissions.

Projected actual emissions are supposed to reflect the maximum annual rate of emissions at which a unit is projected to emit over any one of the five years after completion of a projection like the Unit 2 economizer replacement, considering the unit's historical operations and the company's expected business activity and the company's highest projections of business activity, among other things. *See* 40 C.F.R. § 52.21(b)(41), incorporated by reference into APCEC Reg. 19.904(A) and into the SIP at 40 C.F.R. § 52.170(c). If EAI truly projected a decrease in production of electricity, it is questionable how the company could have economically justified

[36] This is based on the gross MW-hours generated as reported by EAI to EPA's Clean Air Markets Database.

the expense of replacing the economizer. The fact that EAI's projections of electricity produced at Unit 2 were so much lower than the electricity actually produced during the baseline period is a strong indicator that EAI's projections of future actual emissions were not developed in conformity with the applicable PSD rules, which require such projections to reflect the maximum actual rate of emissions and the EAI's highest projections of business activity. Similarly, this disparity may also reflect other legally erroneous aspects of EAI's analysis.

Moreover, actual electricity produced in 2009 one year after the economizer replacement at Unit 2 makes clear that EAI's projections of electricity to be generated at Independence Unit 2 in the five years after the economizer replacement were vastly underestimated. In 2009, Independence Unit 2 produced 6,525 GW-hrs (gross).[37] This is 20% greater than the highest projections made by EAI in any one of the five years after the economizer replacement. This actual generation data proves that EAI's projections of emissions after the economizer replacement were not grounded in reality.[38] And 2009 does not appear to be an anomaly. In the

---

[37] Based on data reported by EAI to EPA in the Clean Air Markets Database.

[38] It is also important to note that the assumptions relied upon by EAI for projected future electricity generation for Unit 2 bear no relation to the assumptions that EAI relied upon in projecting future emissions for Independence Unit 1 after the replacement of the economizer in 2009 at that unit. Specifically, EAI projected an increase in heat input to the Unit 1 boiler in each of the five years after the replacement of the economizer as compared to baseline emissions, which necessarily means that EAI projected an increase in MW-hrs produced at the unit. *See* ISES Exhibit C to EAI's October 7, 2010 letter to ADEQ, Attachment to September 19, 2008 EAI letter to ADEQ Entitled ISES2 Heat Rate Improvement Study (Ex. 14B). (Note that EAI did not provide its projections of post-change electricity production for the Unit 1 economizer project in ISES Ex. C.) Thus, EAI's projections of electricity generation at Unit 2 for the five years after the replacement of the economizer appears to be arbitrary, especially when one considers that Independence Units 1 and 2 are virtually identical units, are co-located at the same plant, and areoperated by the same entity

first nine months of 2010, Unit 2 produced 4,884 GW-hrs (gross) of electricity.[39] Thus, in the first nine months of 2010, the Unit 2 produced more electricity than EAI projected for the entire year of 2012.

The fact that Independence Unit 2 actual produced much more electricity than projected by EAI in its projected future actual emissions calculations for the economizer replacement shows that EAI improperly evaluated projected future actual emissions. Not only did the unit produce much more electricity than EAI assumed would occur, but the unit also had significantly higher heat input and significantly higher emissions than projected by EAI.

Table 3: Comparison of EAI's Projected Future Actual Emissions to 2009 Actual Emissions for Independence Unit 2.

2006 - 2007 Baseline Emissions and Related Data			
Gross MW-hrs Generated/yr	Heat Input to Boiler, MMBtu/yr	SO2, tpy	NOx, tpy
5,999,366	64,487,008	14,077	7,963
EAI's Maximum Projected Future Actual Emissions and Related Data			
5,451,000	61,697,958	13,468	7,618
2009 Actual Emissions and Related Data			
6,525,058	64,649,132	15,171	7,738
2009 Actual Emissions minus Baseline Emissions from 2006-2007			
525,692	162,124	1,094	-225

Notes: Baseline data and 2009 data from EPA's Clean Air Markets Database. EAI's projected future actual emissions from ISIS Exhibit C to EAI's October 7, 2010 submittal to ADEQ (Ex. 14B).

Based on the fact that the 2009 actual emissions data is significantly greater than EAI's projections and that it shows a 1,094 tpy increase in SO2 above the 2006-2007 baseline

---

[39] Based on data reported by EAI to EPA in the Clean Air Markets Database.

emissions, EPA must object to the Independence permit because EAI's projections were patently inaccurate and/or based on legally erroneous assumptions and because the replacement of the economizer significantly increased at least SO2 emissions at Unit 2. As EPA said in its Technical Support Document for the currently applicable PSD regulations:

> If the post-change annual emissions rate of a pollutant from the emissions unit(s) that is modified results in a significant emissions increase at the emissions unit(s), and the emissions rate is inconsistent with the pre-change projection, then the source should report this to the reviewing authority. If this increase is related to the physical or operational change, then the source is required to comply with the major NSR requirements, including an evaluation of BACT, and an analysis of air quality impacts to ensure that the major modification does not cause or contribute to a violation of any NAAQS or PSD increments. Moreover, the source may be subject to an enforcement action for being in violation of the major NSR requirements.

See EPA's Technical Support Document for the Prevention of Significant Deterioration and Nonattainment Area New Source Review Regulations, November 2002, at I-4-25. EPA also stated that "[w]e believe the post-change actual emission projection must be validated at all times to adequately protect and safeguard the environment and human health." *Id.* at I-4-26. EAI's 2009 emissions have invalidated its assessment of baseline actual emissions to projected future actual emissions as a result of the economizer project. Therefore, the unit must be required to comply with PSD permitting requirements as a major modification for at least SO2 if not other regulated NSR pollutants.

Even if 2009 emissions did not show a significant increase in SO2 emissions at Unit 2, a more appropriate projection of actual emissions after the replacement of the economizer would show a significant emission increase of at least SO2, and likely NOx, would occur as a result of the economizer replacement at Unit 2. Sierra Club has conducted such an analysis of projected future actual emissions for the economizer replacement at Unit 2, although it does not likely reflect the maximum annual rate of emissions that would be projected in any one of the five years after the economizer replacement as discussed below.[40]

For the purposes of illustrating that PSD was triggered by the Unit 2 economizer replacement, Sierra Club relied upon EAI's selection of 2006-2007 emissions as reflective of baseline actual emissions for the economizer project at Independence Unit 2 and the emissions and related data submitted by EAI to EPA's Clean Air Markets Database. As previously stated, this analysis revealed that Unit 2 lost an average of 34 hours per year due to forced outages related to the economizer. However, based on the PSD violations Sierra Club has found at both Units 1 and 2 as described in Issues #1 and 2 above (relating to changes in EPA's 1978 BACT requirements and the major modification due to the fuel change), EAI could not have legally accommodated the emission increase during the baseline period. Emissions of SO2 and NOx should have been lower and reflective of BACT. Indeed, baseline actual emissions should have been reduced significantly due to these non-compliant emissions. *See* 40 C.F.R. §52.21(b)(48)(i)(b), incorporated by reference into APCEC Reg. 19904(A), approved into the X SIP at 40 C.F.R. 51.170(c).

Projected future actual emissions were determined as follows: First, the heat rate was determined over the baseline period by dividing total gross MW-hrs generated by total heat input in MMBtu from the data reported to EPA's Clean Air Markets Database. Then the increased

[40] Sierra Club's analysis still underestimates projected future actual emissions from the economizer replacement at Unit 2.

MW-hrs generated from an additional 34 hours of available operating time was calculated, based on the average hourly gross MW production over the 24-month baseline period.[41] By using this method, it was assumed that the unit would be operated at the same utilization factor after the economize r replacement as it was during the baseline period. Thus, it was determined that an additional 26,492 MW-hrs could be generated with the replacement of the economizer. Note that EAI determined there were 57,762 MW-hrs during the two year baseline period (or 28,881 MW-hrs on average per year) due to the economizer at Unit 2 during the 2006-2007 baseline period. *See* ISES Exhibit C to EAI's October 7, 2010 letter to ADEQ, Attachment to September 19, 2008 EAI letter to ADEQ Entitled ISIS #2 Economizer - NSR Actual to Future Projected Actual Calculation (Ex. 14B). Because Sierra Club does not know the basis for this number, it was not relied upon. But clearly it shows an even greater increase in MW-hrs than Sierra Club used in its emission calculations, which would equate to higher emissions than what Sierra Club projected.

Then, based on the heat rate during the baseline period, the increased heat input to the boiler expected with another 34 hours of operation per year was calculated. Based on the gross MW-hrs generated and the total heat input reported to EPA's Clean Air Markets Database during the 2006-2007 baseline period, the heat rate during the baseline period was determined to be 10,749 Btu/kWhr.

EAI claimed a 0.97% increase in the heat rate was expected with the replacement of the economizer at Unit 2 and EAI appears to have taken that into account in its projections of future actual emissions of Unit 2. *Id.* Sierra Club did not take that into account for numerous reasons.

---

[41] That is, the total MWs generated over the baseline period was divided by the actual hours of operation during the baseline period to come up with an average MW/hr rate.

First, EAI provided no explanation or documentation to support and technically justify this improvement in heat rate. EAI did not demonstrate that the heat rate improvement was entirely due to the economizer replacement or that the claimed improvement represented anything more than a transient impact from the economizer replacement. A 0.97% improvement in the heat rate is about 104 Btu/kWhr. This is much higher than the heat rate improvement that EAI claimed would be experienced at the virtually identical White Bluff Unit 1 when its economizer was replaced in 2006.[42] Specifically, EAI projected the economizer replacement at White Bluff Unit 1 would result in only a 59 Btu/kWhr improvement in heat rate. *See* July 31, 2006 Submittal from EAI to ADEQ, attachment entitled White Bluff 1 Heat Rate Improvement Study (Ex. 16). In addition, it is unlikely that any heat rate improvement gained from the replacement of the economizer would be permanent. Instead, any heat rate improvements due to the replacement of the economizer would likely be transient and would lessened over time. Further, if the unit had a heat rate improvement, it would likely result in the unit getting dispatched more often because it would be less expensive to operate. Such increased utilization due to the lower heat rate would likely cancel out the decreased emissions due to lower heat rate. Along with not using EAI's projections of improved heat rate, Sierra Club also did not attempt to account for any increased utilization of the Unit 2. Instead, for purpose of illustrating the claims asserted in this petition, Sierra Club simply assumed the unit would be operated at the same utilization factor after the economizer replacement as occurred during the baseline period except that the unit would operate for an additional 34 hours.

---

[42] White Bluff Unit 1 is the same size and burns the same or similar coal as Independence Unit 2.

Emission factors for SO2 and NOx were conservatively based on the average emission factor over the two year baseline period,[43] and those emission factors were then used with the projected heat input to calculate SO2 and NOx emissions after replacement of the economizer. Using this method, Sierra Club demonstrates that the Independence Unit 2 economizer replacement should have been projected to result in an emissions increase of 76 tons per year of SO2. This calculation of baseline actual emissions subtracted from projected future actual emissions clearly shows a significant increase of SO2. *See* Table 4 below.

[43] Projected actual emissions is supposed to be based on the "maximum annual rate" of emissions in any one of the five years after completion of a project, so using the average emission rate over the 2 year baseline period likely underestimates emissions. Indeed, in 2009, Independence Unit 2 had an emission rate of SO2 of 0.469 lb/MMBtu as compared to the SO2 emission rate over the 2006-2007 baseline period of 0.437 lb/MMBtu. Had even a slightly higher NOx emission rate been used (such as 0.001 lb/MMBtu higher), and the projected increase in NOx emissions would have been significant. Had the actual 2009 SO2 rate of 0.469 lb/MMBtu been used, and the projected emission increase would have been over 1000 tpy SO2. For these reasons, Sierra Club believes that the economizer replacement may also constitute a major modification for NOx.

Table 4: Baseline Actual Emissions and Projected Actual Emissions for the Economizer Replacement Project at Independence Unit 2

Baseline Actual Emissions for 24 Month Period January 2006 to December 2007		
SO2	**NOx**	**Gross MW-hrs Generated/year**
14,077 tpy	7,963 tpy	5,999,366 MW-hrs
Projected Future Actual Emissions With Additional 34 hours of Available Operating Time		
SO2	**NOx**	**Gross MW-hrs Generated/year**
14,339 tpy	8,147 tpy	6,025,493 MW-hrs
Project Actual Emissions - Baseline Actual Emissions		
SO2	**NOx**	
78 tpy	37 tpy	

Note: All data based on data reported by EAI to EPA's Clean Air Markets Database.

Based on the above information, it is clear that the replacement of the economizer should have been projected to result in a significant emission increase of at least SO2. However, it must be noted that Sierra Club does not consider this projection of future actual emissions to be a complete analysis of projected actual emissions for the Independence Unit 2 economizer project because it does not necessarily reflect "the maximum annual rate . . . in any one of the 5 years" after completion of the Unit 2 economizer replacement as required by 40 C.F.R. §52.21(b)(41)(i); incorporated by reference into APCEC Reg. 19.904(A). It is not necessarily appropriate to use the same utilization factor in projecting actual emissions for each of the five years after the economizer replacement because there may be some years in which the unit is utilized more. For example, utility companies typically plan major outages 5 years in advance for an electric utility unit, and in some years, the unit will be down for major planned outages for longer periods than in other years. This is demonstrated by looking at the scheduled complete outages as reported to the Arkansas PSC by EAI over the five year contemporaneous period in the FERC Form 1 Reports. During the 2006-2007 baseline period, Independence Unit 2 had over 1,000 hours of scheduled complete outages on average. *See* Exs. 10D at Supp. E-5 and 10E at Supp. E-5. However, in 2005, Unit 2 had approximately 500 hours of scheduled complete outages. *See* Ex. 10 C at Supp. E-5. Given that the 2006-2007 baseline period reflects a period of significant hours of planned outages, a higher utilization rate due to less planned outage time should have been projected for at least one of the five years after the economizer replacement. Thus, the maximum annual emissions in any one of the five years after the Unit 2 economizer replacement would likely be much greater than the projected emissions provided in Table 4 above. In fact, Unit 2 would only have to be operated 3 more hours in one of the five years after the economizer project for a significant emission increase of NOx to be projected.

Thus, the economizer replacement at Independence Unit 2 should have been projected to result in a significant emissions increase of SO2 and likely also NOx, if not other regulated NSR pollutants. The replacement of the economizer should have also been projected to result in a significant net emissions increase of at least SO2 and likely NOx. That is because the only reductions that can be taken into account in determining net emissions increase are those reductions that are contemporaneous and creditable. To be creditable, the emission reduction would have had to be enforceable as a practicable matter before construction on the economizer replacement project commenced. *See* 40 C.F.R. §52.21(b)(3), incorporated by reference into APCEC Reg 19.904(A) and into the SIP at 40 C.F.R. §52.170(c). There were no such creditable and contemporaneous emission reductions at Independence Unit 2. Therefore, both a significant emission increase and a significant net emissions increase of SO2 and also likely NOx should have been projected for the replacement of the economizer at Unit 2. Because the Independence facility is a major stationary source of at least SO2, the economizer replacement project, associated as it was with significant emission increases and significant net emission increases of SO2, was a major modifications for SO2 at the Independence facility. *See* 40 C.F .R. § 52.21(b)(2), incorporated by reference into APCEC Reg. 19.904(A) and into the SIP at 40 C.F.R. §52.170(c).

ADEQ did not issue any permit or permit modification for the economizer replacement at Independence Unit 2. No evaluation of compliance with the PSD permitting requirements was done for the significant emission increases that would result from the economizer replacement. Therefore, the Independence Title V permit is deficient because it omits requirements applicable to Independence Unit 2 including emission limits reflective of BACT for SO2 if not also NOx and other regulated NSR pollutants.

C. The Economizer Replacement at Independence Unit 2 Did Not Constitute Routine Maintenance, Repair and Replacement

(1) *Summary of Routine Maintenance Issues*

As shown above, the economizer replacement project at Independence Unit 2 was a major modification for SO2 if not other regulated NSR pollutants. However, the definition of "major modification" in the applicable PSD regulations does contain an exemption for routine maintenance," providing that a physical change or change in the method of operation at a major stationary source shall not include "routine maintenance, repair and replacement." *See* 40 C.F.R. § 52.21(b)(2)(iii)(a).

To fall within this exception, the burden 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 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"); *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.").

No such demonstration that this exception applies has been made by either EAI or ADEQ. EAI did not claim the economizer replacement project at Independence Unit 2 was "routine maintenance" when it provided ADEQ with notice of the proposed project, only that it was a "maintenance project." September 19, 2008 Letter from EAI to ADEQ (Ex. 1 to Ex. 3 of this petition). And EAI has not provided ADEQ with the information necessary for ADEQ to have performed an adequate routine maintenance analysis.[44] In fact, ADEQ has not yet made any determination that this project constitutes routine maintenance. However, EAI has very recently claimed in response Sierra Club's public comments on the draft Independence Title V permit that

[44] There was essentially no information provided to ADEQ by EAI on the nature or extent of the Unit 2 economizer replacement project or relating to the purpose, frequency or costs of that project.

this project constituted routine maintenance. This contention lacks merit as a matter of law.

As explained below, the routine maintenance exemption is a *de minimis* exception to the general modification rule in the Clean Air Act. Because the modification provision in the statute contains no routine maintenance exception, EPA's authority to create the exception was extremely limited, and EPA has properly interpreted this exception narrowly. Under that narrow interpretation, the massive economizer replacement project undertaken here cannot fall within the exception.

(2) *A Regulatory Exception to a Broad Statutory Mandate Must be Narrowly Construed.*

The routine maintenance exception provided by EPA in 40 C.F.R. § 52.21(b)(2)(iii)(a) does not even exist in the Clean Air Act itself. Rather, the statutory provision governing "modification" broadly covers "any physical change":

> The term "modification" means ***any*** physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.

42 U.S.C. § 7411(a)(4) (emphasis added). Consequently, as a regulatory exception to a broad statutory provision, the "routine maintenance" exception must be narrowly construed. *Kimel v. Fla. Bd. of Regents*, 528 U.S. 62, 87 (U.S. 2000); *Rugiero v. United States DOJ*, 257 F.3d 534, 543 (6th Cir. 2001); *O'Neal v. Barrow County Bd. of Comm'rs*, 980 F.2d 674 (11th Cir. 1993).

(3) *The Clean Air Act's Modification Provision Applies to All Physical Changes. Therefore, EPA Was Only Authorized to Create a De Minimis Exception to this Provision.*

Cases examining the Clean Air Act's modification provision, 42 U.S.C. § 7411(a)(4), have noted its sweeping applicability. *Alabama Power Co. v. Castle*, 636 F.2d 323, 400 (D.C.

Cir. 1979) (term "modification" not limited to physical changes exceeding a certain magnitude). The definition of physical or operational change is so broad in fact that EPA has declared that, standing alone, it would encompass the repair or replacement of a single leaky pipe. *Wisconsin Electric Power Co. v. Reilly*, 893 F.2d 901, 905 (7th Cir. 1990)(hereinafter "*WEPCO*") , 57 Fed. Reg. 32314, 32316 (July 21, 1992).

Accordingly, the D.C. Circuit, the Circuit empowered to review EPA national rulemakings, *see* 42 U.S.C. § 7607, has consistently interpreted this statutory provision to say that EPA, in implementing the PSD program, only has the authority to fashion exemptions based on *de minimis* or administrative necessity. *See New York v. EPA*, 443 F.3d 880, 886 (D.C. Cir. 2006), cert denied, 550 U.S. 928 (hereinafter "*New York II*"); *Alabama Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1980). In *Alabama Power*, the D.C. Circuit struck down an earlier iteration of the PSD regulations in part because EPA had exempted sources that emit less than 50 tons per year. *Id.* at 355-56. The court there advised EPA that if it chose to refashion an exemption, it could only do so for reasons of administrative necessity, *id.* at 357-60, or to exempt *de miminis* matters. *Id.* at 360-61.

In *New York II*, the D.C. Circuit addressed a rulemaking effort by EPA to redefine the routine maintenance exclusion to exempt from the modification provisions the replacement of any component as long as the cost of the project did not exceed twenty percent of the cost of the process unit. *Id.* at 884. The D.C. Circuit struck down this rule noting that since Congress had been clear that modifications were to cover any physical change, the agency only had the authority to exempt de minimis changes. *Id.* at 888. In defining what *de minimis* is, the *New York II* court noted "de minimis non curat lex ('the law cares not for trifles')" (citing *Wisconsin*

Dep't of Revenue v. William Wrigley, Jr., Co., 505 U.S. 214, 231(1992)) and referred to its opinion in *Shays v. FEC*, 414 F.3d 76, 113-14 (D.C. Cir. 2005), where that court said: "situations covered by a de minimis exemption must be truly de minimis. That is, they must cover only situations where 'the burdens of regulation yield a gain of trivial or no value.'"

(4) *EPA Has Been Consistent In Narrowly Construing the Routine Maintenance Exception, Examining the Nature, Extent, Frequency, and Cost of a Project to Ensure that Only De Minimis Projects Were Exempted.*

Since well before the project at issue occurred in approximately 2008, EPA obeyed the Clean Air Act's statutory mandate and construed the routine maintenance exception narrowly. *See New York II*, 443 F.3d at 884 (Until EPA attempted in 2003 to revise the routine maintenance exception, it had "for over two decades defined the RMRR exclusion as limited to '*de minimis* circumstances.'")(quoting 68 Fed. Reg. at 61272); *see also* 70 Fed. Reg. at 33841 (June 10, 2005) (where EPA confirmed again that prior to the Equipment Replacement Rule, it "had interpreted the exclusion as being limited to *de minimis* circumstances."). A review of EPA's policy pronouncements from 1987 to 2000 confirms this conclusion.

The first interpretation of the exclusion that addressed coal-fired power plants was the 1988 Clay Memo (Ex. 17), which set forth EPA's WEPCO applicability determination upheld by the Seventh Circuit in *WEPCO*, 893 F.2d at 910. In that applicability determination, EPA stated that it would make determinations regarding application of the routine maintenance exclusion based upon a case-by-case analysis of four factors: the nature and extent, purpose, frequency, and cost of the project. *Id.* at 3. Those factors were not to be analyzed in a vacuum, however. EPA acknowledged the sweeping scope of the statutory modification requirement and the extremely limited nature of the routine maintenance exclusion:

> The very 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: other than certain uses of alternative fuels not relevant here, only "routine maintenance, repair, and replacement" is excluded from the definition of physical change.

Id. (emphasis added). In the very next paragraph of the memo, EPA goes on to specify that the exclusion exempts: "[R]egular, customary, or standard undertaking[s] for the purpose of maintaining [a] plant in its present condition. *Id.* at 3-4.

EPA confirmed this "very narrow" interpretation of the routine maintenance exclusion in 2000. *See* May 23, 2000 Detroit Edison Applicability Determination, at pdf pp. 16-17, n. 2 ("Just as other exclusions from the new source provisions are limited to narrow circumstances, one should read the exclusion for routine activity similarly.") (Ex. 18). Here EPA noted that:

> [D]etermining routineness appropriately involves considering whether the activity is frequent (is it "repetitious"), whether it is of significant scope (is it "commonplace"), and whether it is for a customary purpose or is being accomplished in a customary fashion (is it "in accordance with established procedure").

Id. at 8.

Accordingly, the function of each factor of EPA's four-factor test (nature and extent, purpose, frequency, and cost) is to facilitate the classification of a project as a *de minimis*, repetitious, commonplace activity, or not. In other words, whether it is a regular, customary, or standard undertaking for the purpose of maintaining a plant in its present condition. *Id.* at 9. EPA elaborated on the purpose of each factor in the 2000 Detroit Edison Applicability Determination:

Nature

- Whether major components of a facility are being modified or replaced; specifically, whether the units are of considerable size, function, or importance to the operation of the facility, considering the type of industry involved;

- Whether the change requires pre-approval of a state commission, in the case of utilities;

- Whether the source itself has characterized the change as non-routine in any of its own documents;

- Whether the change could be performed during full functioning of the facility or while it was in full working order;

- Whether the materials, equipment and resources necessary to carry out the planned activity are already on site;

Extent

- Whether an entire emissions unit will be replaced;

- Whether the change will take a significant time to perform;

- Whether the collection of activities, taken as a whole, constitutes a non-routine effort, notwithstanding that individual elements could be routine;

- Whether the change requires the addition of parts to existing equipment;

Purpose

- Whether the purpose of the effort is to extend the useful life of the unit; similarly, whether the source proposes to replace a unit at the end of its useful life;

- Whether the modification will keep the unit operating in its present condition, or whether it will allow enhanced operation (*e.g.*, will it permit increased capacity, operating rate, utilization, or fuel adaptability);

Frequency

- Whether the change is performed frequently in a typical unit's life;

Cost

- Whether the change will be costly, both in absolute terms and relative to the cost of replacing the unit; and

- Whether a significant amount of the cost of the change is included in the source's capital expenses, or whether the change can be paid for out of the operating budget (*i.e.*, whether the costs are reasonably reflective of the costs originally projected during the source's or unit's design phase as necessary to maintain the day-to-day operation of the source);

Detroit Edison Applicability Determination at pdf. pp 20-21 (Ex. 18).[45]

Consistent with and in proper deference to the EPA's interpretation of the routine maintenance exemption, most courts have construed of the routine maintenance exemption in a narrow manner. *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 modification."). Three hallmarks of the RMRR exemption have been identified:

> First, the exemption applies to a narrow range of activities, in keeping with the EPA's limited authority to exempt activities from the [CAA]. Second, the exemption applies only to activities that are routine for a generating unit. The exemption does not turn on whether the activity is prevalent within the industry as a whole. Third, no activity is categorically exempt. [The] EPA examines each activity on a case-by-case basis, looking at the nature and extent, purpose, frequency, and cost of activity.

Sierra Club v. Morgan, No. 07-C-251-S 2007 U.S. Dist. LEXIS 82760, at *33-34 (W.D. Wis. 2007) (quoting *Ohio Edison*, 276 F. Supp. 2d at 834 (quoting *United States v. S. Indiana Gas and Elec. Co.*, 245 F. Supp. 2d 994, 1008 (S.D. Ind. 2003) (hereinafter "SIGECO")). And in *Ohio Edison*, 276 F. Supp. 2d at 834, the district court described the

[45] It should be noted that ADEQ does not appear to have made any meaningful attempt to objectively evaluate any of these questions in depth. And ADEQ clearly has not obtained the raw data and information from which an adequate routine maintenance analysis could be performed.

fundamental differences between routine maintenance and non-routine capital projects:

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

(5) *The Economizer Project At Independence Unit 2 Cannot Legitimately Be Considered Routine Maintenance*

There is no question that the 2008 economizer replacement project at Independence Unit 2 constituted a "physical change." And this work was clearly not exempt from PSD applicability as "routine maintenance" work. Other than calling that project "maintenance," Entergy has never submitted any documentation to demonstrate that the Unit 2 economizer replacement project constituted routine maintenance according to the applicable four factor test. In fact, such a showing would be impossible in this context.

The nature and extent of the Unit 2 economizer replacement project was exceptional. It had to have represented a massive undertaking for Entergy. Both Independence Units 1 and 2 each have a nominal generating capacity of 850 MW. *See* Draft Independence Title V Permit at 5, 15. Although project specific data is not presently available to Sierra Club, it is beyond question that replacing an economizer in an 850 MW unit in 2008 was expensive and complex task which took a significant amount of time, effort and money to accomplish. An economizer replacement project would necessarily involve removing a massive amount of tubing from the inside of boiler and replacing that tubing with an equally massive amount of materials. To accomplish such a project would probably require a hole to be cut into in the boiler and the installation of complex rigging equipment to move the tubing in and out the boiler. This work would consume massive amounts of man hours and would in most instances require the hiring of outside contractors to assist in the work. And the planning and design phase associated with such a project would generally take place over a long period of time.

The purpose of this project is not entirely clear but appears likely that one purpose was to improve availability and reliability of the unit in question. This would have meant eliminating outage time that was clearly occurring regularly leading up to the time that the economizer replacement project was performed in 2008.[46] Another purpose for this project may have been to eliminate plugging or erosion problems in the economizer and thereby to extend the life of the boiler in question.

Furthermore, economizer replacement projects are never performed frequently. No evidence has been submitted that suggests an economizer replacement had ever been performed before the economizer replacements at Independence Units 1 or 2 in 2009 and 2008. In all likelihood, the Unit 2 economizer replacement project was the first economizer replacement performed in the entire life of the Independence Plant and it occurred after approximately 23 years of service. This is the epitome of an infrequent event. Frequency at the unit in question

[46] Another factor worth noting is that EAI changed the design of its economizer in Independence Unit 1 when that replacement project took place in 2009, going from a staggered to an inline tube design. *See* January 22, 2009 submittal from EAI to ADEQ, Ex. 2 to Ex. 3 of this petition. This probably eliminated or ameliorated erosion and plugging problems in that area of the boiler. *See, e.g.*, 2007 Arkansas Report (Ex. 10E). This was a design change, which would not constitute routine maintenance at all. Although Sierra Club lacks the documentation to confirm it, it appears likely that EAI changed the design of the Unit 2 economizer as well, given that these units are virtually identical.

rather than in the industry as a whole is the standard by which the frequency factor should be evaluated. *Morgan*, 2007 U.S. Dist. LEXIS 82760 at *33-34 (quoting *Ohio Edison*, 276 F. Supp. 2d at 834 (quoting *SIGECO*, 245 F. Supp. 2d at 1008). However, for the sake of argument, if one were to consider the frequency at a "typical" unit within the industry, such a typical unit would still never be expected to replace an economizer "frequently." *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. Rather, an economizer replacement would rarely occur at any typical unit in the industry.

The capital cost of the Independence Unit 2 economizer replacement is not currently available. However, EAI's September 19, 2008 notification letter to ADEQ states that the economizer replacement project at Unit 2 was identical to the economizer replacements at EAI's White Bluff units. The costs of an economizer replacement at Entergy's White Bluff Plant on a comparable 850 MW unit was approximately $16 million[47] and it is fair to assume that the costs of the Independence Unit 2 replacement were in that range. Moreover, it is virtually assured that such a cost would be accounted as a capital expense and would not have been paid for out of Independence's maintenance budget. No matter how it is evaluated, the cost of a major economizer in the range of $16 million is a large amount of money and weighs against a determination that the Independence Unit 2 economizer replacement project was routine

---

[47] *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. 19).

maintenance. *See, e.g., Ohio Edison*, 276 F. Supp. 2d at 860 ("this Court finds that the accounting and budgeting treatment of the activities at issue as capital expenditures to be highly probative of whether the activities can be considered routine maintenance, repair or replacement for purposes of the CAA."), at 844-45, 856-62 (economizer and secondary superheater outlet pendant tube replacement project which cost approximately $5 million, and took 13 weeks to complete did not fall within the RMRR exception); *Morgan,* 2007 U.S. Dist. LEXIS 82760 at *40-42 (project involving, *inter alia*, economizer replacements for three separate units which were intended to increase reliability and availability and cost a total of only $788,899.00 was not routine maintenance).

As discussed above, a common sense application and analysis of the four factor routine maintenance test articulated by EPA confirms that EAI's Independence Unit 2 economizer replacement project cannot legitimately be considered routine maintenance.

D. Summary

In summary, the Independence Title V permit is deficient because it omits applicable PSD requirements applicable to the replacement of the economizer at Unit 2 that occurred in 2008. Those requirements include the imposition of a BACT emission limit for SO2 and likely also NOx, if not other regulated NSR pollutants and could also include other requirements necessary to assure compliance with the NAAQS, PSD increments, and/or to protect Class I air quality related values (AQRVs). *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).

A PSD permit for the economizer replacement would have required more stringent emission limitations and pollution control requirements than what are currently in the

Independence Title V permit. First, a scrubber for SO2 would have been required as BACT. That is because the BACT determination can be no less stringent than the NSPS, 42 U.S.C. § 7479(3), and after September 18, 1978, no coal-fired electric utility boiler could be constructed or modified without a scrubber for SO2. Thus, the Title V permit for Independence is deficient because it omits applicable PSD requirements which must include, if nothing else, the requirement for the installation of SO2 scrubbers at the Independence boilers and impose an emission limit no less stringent than that required in 40 C.F.R. §60.43Da(i)(3) - specifically, 1.4 lb/MWh, 0. 15 lb/MMBtu, or 90% reduction in SO2 emissions on a 30-day rolling average basis. With a proper BACT determination, the SO2 emission limits should be more stringent than these NSPS limits.

Further, the NOx BACT limit cannot be any less stringent than the NSPS limits in 40 C.F.R. § 60.44Da(e)(3). That is, the NOx BACT limit cannot be any less stringent than 1.4 lb/MWh or 0.15 lb/MMBtu, as measured on a 30 day rolling average. The emission limits and requirements of the Independence Title V permit are unquestionably less stringent than these NSPS requirements. And a proper case-by-case BACT determination would likely result in emission limits more stringent than relevant NSPS limits.

Thus, the Independence Title V permit is deficient because it improperly omits applicable requirements of the PSD program including an SO2 and a NOx BACT determination made for the 2008 economizer replacement project at Independence Unit 2 and it lacks a compliance schedule for this PSD violation.[48] Therefore, EPA must object to the Independence Title V

---

[48] In addition, EPA has codified its interpretation that greenhouse gases, including without limitation, carbon dioxide (CO2), will be subject to regulation and required to undergo a BACT analysis as of January 2011. Sierra Club contends that if the Johnson Memo, the EPA

permit.

Issue # 4: The Administrator Must Object to the Independence Title V Permit Because It Fails to Include PSD Requirements Applicable to Replacement of the Economizer at Independence Unit 1.

The draft Independence Title V permit is legally inadequate and must be objected to by EPA because it fails to include PSD requirements applicable to Unit 1 as a consequence of the replacement of the economizer within that unit in 2009.

On January 22, 2009, EAI notified ADEQ that it intended to replace the economizer at Independence Unit 1. (Ex. 2 to Ex. 3 of this petition). Specifically, EAI stated "[t]he project will involve installation of 299 new upper and lower assemblies from the inlet header to the outlet header. The new assemblies are 2 1/8" [outer diameter (OD)] bare tube - in line design, where as the assemblies being replaced are 1 3/4" OD fin tube staggered design." *Id.* EAI also stated "[t]his economizer replacement project will result in a slight improvement in unit efficiency; therefore this project will not increase hourly emission rates. . . ." *Id.* EAI commenced construction on the economizer replacement project for Independence Unit 1 sometime after February 28, 2009 and by April 17, 2009 that work was completed and Unit 1 commenced operations. April 22, 2009 Letter from EAI's M. Bowles to ADEQ's T. Rheaume at 1, (Ex. 4 to Ex. 3 of this petition).

On approximately October 15, 2010, Sierra Club was provided with a set of documents from ADEQ in response to a state freedom of information request which included EAI's responses to Sierra Club's comments on the draft Independence Title V permit. On October 18,

---

Reconsideration, or the codification of that interpretation in the Tailoring Rule are overturned, BACT for greenhouse gases, including CO_2, may be required as a consequence of the economizer replacement at Independence Unit 2.

2010, it was first discovered that EAI's response to Sierra Club's comments included emission calculations for the subject economizer projects from EIA. *See* Independence Steam Electric Station ("ISES") Exhibit C (Ex. 14B). It appears that these calculations were not submitted to ADEQ until approximately October 7, 2010, when EAI provided its response to Sierra Club's comments on the draft Independence Title V permit. October 7, 2010 EAI Response to Sierra Club's Comments on Independence's Title V Permit and Emission Calculations (Ex. 14A). And thus far, ADEQ has not relied on these calculations in any manner or indicated it has any intention to do so in the future. At this juncture, Sierra Club is analyzing EAI's recently produced emissions projections and will endeavor to address them in this petition to extent that it is practicable to do so. However, particularly since ADEQ has not submitted its final response to Sierra Club's comments on the draft Title V permit, much less issued a proposed a final Title V permit, Sierra Club expressly reserves the right to supplement this petition to address EAI's emission projection calculations in more detail, as well as other documents and issues that may arise or become more prominent as the permitting process at ADEQ goes forward.

A. Legal Flaws in EAI's Analysis of Whether the Economizer Replacement at Unit 1 Would Significantly Increase Emissions.

Based on its statements in its January 22, 2009 letter to ADEQ regarding the Unit 1 economizer project, EAI appears to treat projects that improve efficiency and that do not increase the maximum hourly rate of emissions as exempt from PSD review. *See* Ex. 2 to Ex. 3 of this petition. That position is incorrect as a matter of law. A project that improves efficiency can lead to unit being dispatched more often, resulting in increased annual emissions that may exceed significance thresholds and trigger PSD.[49] Further, the emissions increase test for PSD applicability is based on increases in actual emissions on an annual basis, and not on the maximum hourly rate of emissions. *See generally Envtl. Def. v. Duke Energy Corp.*, 549 U.S. 561, 570-581 (2007).

EAI also stated that "[a]ny increase in annual emissions will be due to an increase in electrical demand, not this project."[50] *Id.* The definition of "projected actual emissions" provides that projected actual emissions can exclude:

> [T]hat 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 [40 C.F.R. § 52.21(b)(48)] 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)(c), APCEC Reg. 19.904(A), approved into the SIP at 40 C.F.R. 51.170(c). EAI 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. In its emissions projections that EAI submitted to ADEQ on October 7, 2010, EAI relied in 2006 - 2007 as the baseline period for the Unit 1 economizer replacement project and EAI indicated that there were 503 hours of forced outages or derates during the baseline period. *See* ISES

---

[49] In its September 19, 2008 letter to ADEQ on the Unit 2 economizer replacement, EAI did not make any claims that the replacement of the economizer at Unit 2 would increase efficiency. EAI also did not make any claims regarding whether the hourly emission rates would increase or not. *See* Ex. 1 to Ex. 3 of this petition.

[50] EAI also did not make any claims that any increased emissions as a result of the Unit 2 economizer replacement project would be due to demand growth. *See* Ex. 1 to Ex. 3 of this petition.

Exhibit C to EAI's October 7, 2010 submittal to ADEQ, attachment with title "ISES #1 Economizer - NSR Actual to Future Projected Actual Calculation" (Ex. 14B). Based on the data reported by EAI in its FERC Form 1 Reports (Arkanasas Reports), Unit 1 was experiencing numerous derates associated with tube leaks and plugging in the economizer during the company's 2006-2007 baseline period. (Exs. 10D and 10E). Thus, it is highly unlikely that Unit 1 was capable of accommodating EAI's projected increases in electricity demand during the baseline period. And neither ADEQ or EAI has made any technical demonstration on this point. Furthermore, it would be very difficult for EAI to demonstrate that any increase in demand growth was unrelated to the economizer project, since it claimed the project would make the unit more efficient which would result in the unit being dispatched more frequently.

B. EAI's Projection of Future Actual Emissions After Replacement of the Economizer Shows There Will Be a Significant Increase in Annual Emissions.

In the documentation provided to ADEQ on October 7, 2010, EAI provided its emissions analysis of baseline actual emissions compared to future projected actual emissions. *See* ISES Exhibit C to EAI's October 7, 2010 submittal to ADEQ, attachment with title "ISES #1 Economizer - NSR Actual to Future Projected Actual Calculation" (Ex. 14B). In these calculations, EAI provided future emission calculations with and without a heat rate improvement. EAI did not specify what heat rate improvement would be expected with the economizer replacement project and provided no explanation as to why there would be a heat rate improvement and that it would be a permanent heat rate improvement. If there would be a permanent heat rate improvement due to the replacement of the economizer, such heat rate improvement should only be taken into account if EAI also takes into account the increase utilization of the unit that will occur with a lower heat rate (because the unit will be less costly to operate with a lower heat rate). The emissions associated with increased utilization of the unit due to a lower heat rate achieved with the replacement of the economizer could not be excluded from projections of future actual emissions as due demand growth because the increased utilization of the unit would be related to the economizer replacement project. *See* 40 C.F.R. §52.2(b)(i)(c), as incorporated by reference into APCEC Reg. 19.904(A), approved into the SIP at 40 C.F.R.§ 52.170(c).

EAI has failed to provide adequate documentation to make determinations regarding any claims of improved heat rate of the economizer and the impact that would have on unit utilization. However, EAI did provide projections of future emissions both with and without the heat rate improvement, and both of these projections show that significant increases in SO2, NOx and other regulated NSR pollutants as compared to 2006-2007 baseline emissions in at least one of the five years of post-project emissions. *Id.* The table below provides this data.

Table 5: EAI's Evaluation of Actual to Future Actual Emissions at Independence Unit 1 Due to Economizer Replacement Project.[51]		
2006-2007 Baseline Actual Emissions		
SO2	**NOx**	**PM**
13,779 tpy	8,045 tpy	586 tpy
Highest Year of Future Projected Actual Emissions with Heat Rate Improvement		
14,925 tpy	8,715 tpy	634 tpy
Projected Actual Emissions (w/Heat Rate Improvement) Minus Baseline Emissions		
1,146 tpy *(>40 tpy)*	670 tpy (>40 tpy)	48 tpy *(>25 tpy)*
Highest Year of Future Projected Actual Emissions Without Heat Rate Improvement		
14,986 tpy	8,750 tpy	637 tpy
Projected Actual Emissions (without Heat Rate Improvement) Minus Baseline Emissions		
1,207 tpy *(>40 tpy)*	705 tpy *(>40 tpy)*	51 tpy *(>25 tpy)*

Thus, clearly, EAI's own projections show that the economizer replacement project at Independence Unit 1 would result in a significant emission increase of at least SO2, NOx, and PM. There does not appear to have been any emissions reductions that could be credited against these projected significant emission increases at Unit 1. As a consequence, the economizer replacement should have been projected to result in a significant net emissions increase as well as a significant emission increase of at least SO2, NOx and PM. In addition, EAI's emission proj ections show an increase of 25-26 tpy of condensible particulate matter. *See* ISES Exhibit C to EAI's October 7, 20 10 submittal to ADEQ, attachment with title "ISES #1 Economizer - NSR

[51] Source of data: ISES Exhibit C to EAI's October 7, 2010 submittal to ADEQ, attachment with title "ISES #1 Economizer - NSR Actual to Future Projected Actual Calculation" (Ex. 14B). PSD significance levels are identified in 40 C.F.R. §52.21(b)(23), incorporated by reference into APCEC Reg. 19.904(A), approved into the SIP at 40 C.F.R. §52.170(c).

Actual to Future Projected Actual Calculation" (Ex. 14B). Because all condensible particulate matter from a coal-fired boiler is in the size range of 2.5 micrometers or less, this means EAI projected a significant emission increase of PM2.5 as well for which the significance level is 10 tpy. *See* 40 C.F.R. §52.2 1(b)(23)(I). In addition, because the projected increase in SO2 and NOx emissions exceed the 40 tpy significance levels, those emission increases are significant for PM2.5. *Id.*

Morever, for all the same reasons that the economizer replacement at Independence Unit 2 cannot be considered routine maintenance, *see* discussion *infra* at Issue #3, Section C, the economizer replacement at Unit 1 was likewise clearly not a routine maintenance project. The only readily apparent difference between those two projects was that the replacement of Unit 1's economizer, without question, involved a design change. And that fact only further serves to confirm that this economizer replacement project did not constitute routine maintenance.

While it appears that EAI determined there would not be a significant emission increase in any regulated NSR pollutant because any increase would be due to increased demand and not due to the economizer, EAI has not provided any technical support for the self-serving contention that its projections of emissions were due solely to increased demand and not in any way associated with the economizer project.

Furthermore, EAI has not provided any documentation to show it could have accommodated the increased demand during the baseline period. Unit 1 had to have been capable of legally and physically accommodating the increased electricity demand during the baseline period. As shown in the Arkansas Reports, the unit was experiencing significant derates due to pluggage in the economizer during 2006-2007. The economizer that EAI installed was a different design than originally installed at the unit. The original economizer was a fin tube staggered design, and the new economizer bare tube - in line design. *See* Ex. 2 to Ex. 3 of this petition. Clearly, the new design would result in less pluggage and erosion in the economizer than occurred prior to its replacement. And the pluggage that was occurring in the economizer during the baseline period was causing derates. *See* Exs. 10D and 10E. Thus, the admittedly limited available evidence strongly suggests that Unit 1 could not have accommodated any increase in electrical demand during the baseline period that EAI has projected for the 5 years after replacement of the economizer.

Because EAI has failed to demonstrate that all of its projected increase in emissions were not in any way related to the economizer and could have physically been accommodated at Unit 1 during the baseline period, EAI has no justification to use the demand growth exclusion to claim no significant emission increase would occur as a result of the economizer replacement at Unit 1.

Additionally, based on the PSD violations we have found at both Units 1 and 2 as described in Issues #1 and 2 above (relating to changes in EPA's 1978 BACT requirements and the major modification due to the fuel change), EAI could not have legally accommodated the emission increase during the baseline period. Emissions of SO2, NOx, and PM should have been lower and reflective of BACT. Indeed, baseline actual emissions should have been reduced significantly due to these non-compliant emissions. *See* 40 C.F.R. §52.21(b)(48)(i)(b), incorporated by reference into APCEC Reg. 19904(A), approved into the SIP at 40 C.F.R. 51.170(c).

Thus, for all of the above reasons, the economizer replacement project at Independence Unit 1 should have been subject to PSD as a major modification of SO2, NOx, PM, PM2.5, if not other regulated NSR pollutants.

Sierra Club raised this issue in its August 9, 2010 comment letter to ADEQ. Ex. 3 at 13-15. When it submitted its comments, Sierra Club did not yet have access to EAI's emission projections for Unit 1 that were submitted to ADEQ on October 7, 2010 and, therefore, did not specifically discuss EAI's own projections of significant emission increases of SO2, NOx, PM, PM-2.5 and any others or the ramifications of those calculations. *See* discussion *infra*. Obviously, it was impracticable for Sierra Club to comment on undisclosed documents within EAI's possession. However, the comments made on the Unit 1 economizer replacement project fairly encompass the arguments made above regarding Unit 1 and EAI's emission projections. The arguments made herein simply amplify Sierra Club's prior comments and provide more specificity. And they otherwise represent a logical outgrowth of Sierra Club's prior comments.

C. Summary

The Independence Title V permit is deficient because it omits applicable PSD requirements applicable to the replacement of the economizer at Unit 2 that occurred in 2008. Those requirements include the imposition of a BACT emission limit for SO2, NOx, PM, and PM2.5 if not other regulated NSR pollutants and could also include other requirements necessary to assure compliance with the NAAQS, PSD increments, and/or to protect Class I air quality related values (AQRVs). *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).

A PSD permit for the economizer replacement would have required more stringent emission limitations and pollution control requirements than what are currently in the Independence Title V permit. First, a scrubber for SO2 would have been required as BACT.

That is because the BACT determination can be no less stringent than the NSPS, 42 U.S.C. § 7479(3), and after September 18, 1978, no coal-fired electric utility boiler could be constructed or modified without a scrubber for SO2. Thus, the Title V permit for Independence is deficient because it omits applicable PSD requirements which must include, if nothing else, the requirement for the installation of SO2 scrubbers at the Independence boilers and impose an emission limit no less stringent than that required in 40 C.F.R. §60.43Da(i)(3) - specifically, 1 .4 lb/MWh, 0. 1 5 lb/ MMBtu, or 90% reduction in SO2 emissions on a 30-day rolling average basis. With a proper BACT determination, the SO2 emission limits should be more stringent than these NSPS limits.

Further, the NOx BACT limit cannot be any less stringent than the NSPS limits in 40 C.F.R. §60.44Da(e)(3). That is, the NOx BACT limit cannot be any less stringent than 1.4 lb/MWh or 0.15 lb/MMBtu, as measured on a 30 day rolling average. Further, the PM BACT limit cannot be any less stringent than required under 40 C.F.R. §60.42Da(c) or (d). That is, the PM BACT limit cannot be any less stringent than 0.14 lb/MWh, 0.015 lb/MMBtu, or 0.03 lb/MMBtu and 99.8% removal.

The emission limits and requirements of the Independence Title V permit are unquestionably less stringent than these NSPS requirements. And a proper case-by-case BACT determination would likely result in emission limits more stringent than relevant NSPS limits.

Thus, the Independence Title V permit is deficient because it improperly omits applicable requirements of the PSD program including BACT determinations made for the 2009 economizer replacement project at Independence Unit 1 and it lacks a compliance schedule for this PSD violation.[52] Therefore, EPA must object to the Independence Title V permit.

CONCLUSION

For the reasons set forth above, this petition should be granted.

Respectfully submitted,

THE LAW OFFICE OF
WILLIAM J. MOORE, III, P.A.
1648 Osceola Street
Jacksonville, FL 32204
Telephone: (904) 685-2172
Facsimile: (904) 685-2172
email: wmoore@wjmlaw.net

By: ____________________
William J. Moore, III
Florida Bar No. 0971812

Attorneys for Petitioner Sierra Club

[52] In addition, EPA has codified its interpretation that greenhouse gases, including without limitation, carbon dioxide (CO2), will be subject to regulation and required to undergo a BACT analysis as of January 2011. Sierra Club contends that if the Johnson Memo, the EPA Reconsideration, or the codification of that interpretation in the Tailoring Rule are overturned, BACT for greenhouse gases, including CO2, may be required as a consequence of the economizer replacement at Independence Unit 2.

CERTIFICATE OF SERVICE

I, William J. Moore, III, certify on October 19, 2010, I sent, via e-mail, a true and accurate copy of the foregoing document, including all exhibits/attachments, to the following addresses listed below:

Lisa P. Jackson
Administrator
United States Environmental Protection Agency
U.S. EPA Ariel Rios Building (AR)
1200 Pennsylvania Ave., NW.
Washington, DC 20460
jackson.lisa@epa.gov

Dr. Alfredo Armendariz
Regional Administrator
U.S. EPA Region 6
1445 Ross Avenue
Suite 1200
Mail Code: 6RAD
Dallas, TX 75202-2733
armendariz.al@epa.gov

Teresa Marks, Director
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317
marks@adeq.state.ar.us

Benjamin T. Jones, Esq.
Arkansas Department of
Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317
jonesr@adeq.state.ar.us

Chuck D. Barlow, Esq.
Assistant General Counsel - Environmental
Entergy Services, Inc.
308 Pearl Street
Jackson, MS 39201
cbarlow@entergy.com

Laura Rafaelli Landreaux, Esq.
Senior Counsel
Entergy Services, Inc.
P.O. Box 551
Little Rock, AR 72201
lraffae@entergy.com

Kelly M. McQueen, Esq.
Perkins & Trotter, PLLC
P.O. Box 251618
Little Rock, AR 72225
kmcqueen@perkinstrotter.com

William J. Moore, III