ARGUED APRIL 13, 2012
DECIDED AUGUST 21, 2012
No. 11-1302 (and consolidated cases) (COMPLEX)

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

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EME Homer City Generation, L.P., et al.,
Petitioners,

v.

United States Environmental Protection Agency, et al.,
Respondents,

_____

On Petitions for Review of an Action of the
United States Environmental Protection Agency

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JOINT OPPOSITION OF INDUSTRY/LABOR PETITIONERS
TO MOTIONS TO LIFT THE STAY

_____

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INTRODUCTION

The undersigned petitioners ("Industry/Labor petitioners") oppose EPA's motion to lift the stay of the Transport Rule.[1] Neither the Supreme Court's decision nor any intervening change in circumstances warrants revisiting this Court's decision to stay the Rule "pending the court's resolution of th[e] petitions for review," Doc.1350421 at 2, which present important issues that remain to be resolved.

Initially, EPA's motion is fundamentally improper. It is premised on EPA's request that this Court "toll" the Rule's compliance deadlines, which imposed emission budgets based on EPA's air-quality projections *for specific years*. Nothing in the record justifies treating 2015 as if it were 2012 despite the intervening changes in air quality. Rather, EPA's own projections show that air quality would improve by 2014—and indeed that many locations would attain the relevant NAAQS by 2014— *without any* good-neighbor emission controls. EPA cannot lawfully regulate the numerous upwind States linked exclusively to these locations. Moreover, important Transport Rule deadlines cannot be changed without modifying other rules that are not before the Court and that implicate policy issues requiring further rulemaking. Until EPA undertakes such rulemaking, the stay cannot be lifted. *See infra* Part I.

In all events, EPA (and ALA) fall well short of demonstrating a stay is no longer warranted. Far from supporting EPA's motion, the Supreme Court's ruling in

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[1] American Lung Association, *et al.* ("ALA") responded in support of EPA's motion and also sought additional affirmative relief. The Industry/Labor petitioners hereby oppose ALA's request for affirmative relief.

EPA v. EME Homer City Generation, L.P., 134 S. Ct. 1584 (2014), is fatal to it. The Supreme Court "agree[d]" with this Court that EPA has a "statutory duty to avoid over-control." *Id.* at 1608–09. And the Transport Rule clearly overcontrols many upwind States. In addition, petitioners have a probability of success on other grounds not addressed in this Court's prior opinion. *See infra* Part II.A.

Moreover, EPA's declarant confirms that petitioners would be irreparably harmed if the stay were lifted. ALA's proposed implementation schedule—rejected as unworkable in the Transport Rule—would magnify these harms. *See infra* Part II.B.

At the same time, lifting the stay would disserve the public interest. Electric generators remain subject to the Clean Air Interstate Rule ("CAIR"), under which widespread attainment has been achieved. EPA has not demonstrated that lifting the stay would bring *any* environmental benefits. Nor has it accounted for the disruption and wasted resources that would result from replacing the existing, effective CAIR regime with an illegal rule that this Court likely will soon set aside. *See infra* Part II.C.

BACKGROUND

EPA and ALA do not accurately present the background of this proceeding. At every stage, petitioners have shown that the Transport Rule's emission budgets exceed EPA's statutory authority. *See, e.g.*, Industry/Labor Br. 19–30 (Doc.1364190);

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Industry/Labor Br. in Opp. to Cert. 9–23; Industry/Labor S. Ct. Br. 15–41.[2] Rather

than undermine these arguments, the Supreme Court's ruling confirms their validity.

In the Transport Rule, EPA imposed emission budgets on upwind States to

reduce the interstate transport of certain air pollutants. This Court held that the

Transport Rule exceeded EPA's authority in "at least three independent" respects.

EME Homer City Generation, L.P. v. EPA, 696 F.3d 7, 23–28 (D.C. Cir. 2012). On

certiorari, the Supreme Court disagreed with only one of these holdings—the

"proportionality" holding. *EME Homer*, 134 S. Ct. at 1603–07.

As to the overcontrol and one-percent "insignificance" threshold issues that

provided the two other "independent" grounds for this Court's invalidation of the

Transport Rule, 696 F.3d at 23, the Supreme Court expressly *"agree[d]"* with this

Court's statutory analysis, 134 S. Ct. at 1608 (emphasis added). As to overcontrol, the

Supreme Court held that "[i]f EPA requires an upwind State to reduce emissions by

more than the amount necessary to achieve attainment in *every* downwind State to

which it is linked, the Agency will have overstepped its authority." *Id.* As to the one-

percent threshold, the Supreme Court held that EPA cannot "demand reductions that

would drive an upwind State's contribution to every downwind State to which it is

linked below one percent of the relevant NAAQS." *Id.*

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[2] The parties' Supreme Court filings are available online at http://www.scotusblog.
com/case-files/cases/american-lung-association-v-eme-homer-city-generation/.

Although the Supreme Court concluded that the possibility that EPA had overstepped its authority in one of these respects did not "justif[y] wholesale invalidation of the Transport Rule," the Court held that an upwind State may maintain an "as-applied" challenge if "it has been forced to regulate emissions below the one-percent threshold or beyond the point necessary to bring all downwind States into attainment." *Id.* at 1608–09. In this regard, the Supreme Court accepted EPA's suggestion that as-applied challenges to the Rule could be considered by this Court on remand. Tr. of Oral Arg. 27–28, *EME Homer*, 134 S. Ct. 1584 (2014) (No. 12-1182).

ARGUMENT

I.   EPA'S MOTION IS AN IMPROPER ATTEMPT TO AVOID NOTICE-AND-COMMENT RULEMAKING.

EPA's motion is a curious one. Although EPA seeks to lift the stay, it does not argue that the Transport Rule can be put into effect as written. For good reason: The Transport Rule adopted emission budgets for specific calendar years, imposing Phase 1 emission budgets for 2012 and 2013 and stricter Phase 2 budgets for 2014 and beyond. *See* EPA Mot., Harvey Decl. ¶12. EPA found that this two-year phase-in was "as expeditious as practicable" given the time required to install the necessary controls. *See* 76 FR 48208, 48282 (Aug. 8, 2011). EPA thus does not contend that the Transport Rule's 2014 emission budgets could feasibly be imposed before 2017.

Instead, EPA asks this Court to change the Transport Rule's compliance deadlines such that the Rule's Phase 1 emission budgets would "apply in 2015 and

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2016 (instead of 2012 and 2013), and the Phase 2 emissions budgets [would] apply in 2017 and beyond (instead of 2014 and beyond)." EPA Mot. 1. EPA also asks this Court to change the deadlines for the "variability limits" that the Transport Rule adopted to restrict interstate allowance trading and use of "banked" allowances. *Id.* at 14. Under the Transport Rule, these limits were scheduled to take effect in 2012, but in a *subsequent* rulemaking, EPA changed their effective date to January 1, 2014, to facilitate allowance trading. 77 FR 10324 (Feb. 21, 2012).

EPA's request for "tolling" ignores that the Transport Rule's emission budgets were set based on EPA's air-quality findings *with respect to specific years. See, e.g.*, 76 FR at 48256–59. EPA nowhere explains why it is appropriate in 2015 to impose emission budgets based on air-quality conditions projected by EPA to exist in 2012, and in 2017 to impose emission budgets based on air-quality conditions projected by EPA to exist in 2014. These budgets cannot be justified on the Transport Rule's record.

Quite the opposite is true: the Transport Rule record shows it would be *illegal* to impose 2012 budgets in 2015. EPA's modeling projected substantial improvement in downwind air quality between 2012 and 2014 even absent *any* good-neighbor regulation. Indeed, EPA projected that many downwind locations would attain the relevant NAAQS in 2014 *without* the Transport Rule (or CAIR). *See* JA2546–637, 2959–62; Industry/Labor Br. 45 & n.28 (Doc.1364190). EPA lacks authority to require emission reductions from States linked exclusively to such locations. *See EME Homer*, 134 S. Ct. at 1608. And if EPA cannot impose such reductions directly, this

Court should not authorize EPA to impose them under the guise of tolling deadlines. Treating 2015 as if it were 2012, and 2017 as if it were 2014, would be the epitome of arbitrary agency action where EPA's own findings show that many downwind locations would attain the NAAQS in 2014 *without* any good-neighbor regulation.

In addition to ignoring its own air-quality findings, EPA's proposal would give regulated parties even less time to prepare for compliance than they had under the Transport Rule. Affected parties had less than six months' notice of the Transport Rule's initial compliance obligations. *See* http://www.epa.gov/airtransport/CSAPR /actions.html (Transport Rule finalized on July 6, 2011, with Phase 1 budgets effective on January 1, 2012). EPA would provide an even *shorter* compliance period here. EPA's request is particularly inappropriate because one of petitioners' original challenges, which this Court did not resolve, is that the Transport Rule compliance deadlines were too short in the first place. Industry/Labor Br. 52–58 (Doc.1364190).

ALA, for its part, proposes to compound this problem by insisting that regulated parties comply with the stricter Phase 2 emission budgets beginning in 2015. *See* ALA Resp. 1–2. In effect, ALA asks this Court to find, based on its made-for-litigation analysis rather than any evidence in the administrative record, that "States can practicably achieve th[e] reductions necessary to meet their Transport Rule Phase 2 assurance levels … in 2015." *Id.* at 17. But EPA made no such finding; indeed, it found the opposite: sources would need two years to install the controls necessary to comply with Phase 2 emission budgets. *See* 76 FR at 48277–78, 48282.

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ALA's contrary position rests on the baseless assertion that regulated parties should have been complying with the Transport Rule even while it was stayed, and indeed, even after it had been *vacated* as unlawful. *See* ALA Resp. 14–15. This would defeat the entire purpose of a stay, which is to *relieve* parties from complying with a challenged regulation until its legality is adjudicated. Indeed, EPA advised regulated parties that, pending further proceedings before this Court on remand, "CAIR remains in place and *no immediate action from States or affected sources is expected*." http://www.epa.gov/airtransport/CSAPR (visited July 29, 2014) (emphasis added).

Moreover, EPA effectively acknowledges that its proposal would require this Court to refashion rules that are not even before the Court and to grant EPA a blank check to make numerous other changes to the regulation that would be required to conform it to the revised compliance deadlines. In asking this Court to toll the variability-limit deadlines along with the Transport Rule's budgets, EPA ignores that those deadlines were not even promulgated in the Transport Rule, but instead were contained in the so-called "First Revisions Rule." *See* 77 FR 10324 (Feb. 21, 2012); 40 C.F.R. §§97.510(b), 97.610(b), 97.710(b) (variability limits will apply "for the control periods in 2014 and thereafter"). The First Revisions Rule was not stayed, and is the subject of separate petitions for review in this Court. EPA Mot., Harvey Decl. ¶25. Although EPA states (correctly) that the variability limits should be delayed to allow trading to develop, *id.* ¶¶29, 34, it does not explain how this Court, on review of the Transport Rule, can rewrite substantive provisions enacted in the First Revisions Rule.

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Nor does EPA explain why this Court should bless its attempt to circumvent notice-and-comment rulemaking to make changes to important regulatory provisions that are not even specified, let alone justified, in its motion. EPA acknowledges that "[t]he Rule contains additional deadlines" that would need to be changed and says that it "would ... tak[e] any necessary administrative action to amend the existing regulatory text in the Code of Federal Regulations to be consistent with this Court's action." *Id.* at 14 n.5. But several of these "additional deadlines" raise policy issues that cannot be addressed through "ministerial actions." *Id.* For example, will EPA continue to bar States from developing different allowance allocations than EPA imposed even though the Transport Rule permitted States to begin doing so in 2013? *See* 76 FR at 48328–29. Or will EPA treat units constructed and made operational since the Transport Rule as "planned" rather than "existing" units? *Id.* at 48284. EPA's "tolling" proposal is in reality a request for this Court's advance authorization to change key regulatory provisions, which EPA has not even identified, without the requisite notice-and-comment rulemaking. *See* 42 U.S.C. §7607(d)(3).

As its sole authority for this extraordinary request, EPA cites this Court's order lifting the stay in *Michigan v. EPA*, No. 98-1497 (D.C. Cir. June 22, 2000). EPA Mot. 15. That order cannot bear the weight EPA puts on it. In contrast to the order EPA and ALA seek here, the order lifting the stay in *Michigan* was entered only *after* all proceedings in this Court had concluded. And it did not authorize EPA to impose illegal emission budgets based on outdated air-quality data or to accelerate compliance

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deadlines for regulated parties. Instead, by extending the deadline for States to submit their implementation plans, it *allowed* the States to account for changed circumstances.

Here, by contrast, EPA seeks permission to impose federal implementation plans directly on regulated sources without regard to how relevant circumstances have changed since 2012. While the Court is hearing from the parties to this case, these parties represent only a small subset of the sources that would be subject to the Rule in just a few months. EPA must undertake a notice-and-comment rulemaking to reset the various deadlines in the Transport Rule and related rules and address the regulatory issues that flow from the new deadlines. Until EPA has conducted such a rulemaking, this Court should not entertain a motion to lift the stay.

II.   THE STAY SHOULD REMAIN IN EFFECT.

In any event, the movants fall well short of demonstrating that the stay is no longer warranted under the traditional test for equitable relief.

A.   The Industry/Labor Petitioners Have A Substantial Probability Of Success On The Merits.

In light of the Supreme Court's ruling, the Industry/Labor petitioners have an overwhelming probability of success on the central statutory arguments they have pressed in this proceeding. They also have a substantial probability of success on the other challenges raised in their prior briefs that this Court did not address.

1.   The Transport Rule overcontrols many upwind States.

As noted, the Supreme Court "agree[d]" with this Court that EPA has a "statutory duty to avoid over-control." 134 S. Ct. at 1608–09. The Court rejected EPA's contentions that overcontrol could be excused because the agency did not "set out" to overcontrol, EPA S. Ct. Br. 54, or that overcontrol is "unavoidable" because *some* upwind States are linked to multiple downwind nonattainment locations, EPA S. Ct. Reply Br. 22. The Supreme Court expressly stated that the Transport Rule would impose "unnecessary" overcontrol if an upwind State is linked solely to locations that would attain the relevant NAAQS with lesser emission reductions. 134 S. Ct. at 1609.

The Transport Rule, in fact, overcontrols several States. This overcontrol resulted from fundamental flaws in EPA's approach to setting emission budgets. EPA used air-quality modeling to determine locations expected to have attainment problems in 2012 absent CAIR-mandated emission controls. 76 FR at 48211. EPA then set thresholds at 1% of each NAAQS. *Id.* at 48236. States whose projected "contributions" met or exceeded this threshold at a given downwind location were deemed "linked" to that location and subjected to budgets. *Id.* In contrast, "States whose contributions [we]re below these thresholds" were found by EPA to "not significantly contribute to nonattainment" and thus were not subject to budgets. *Id.*

For regulated upwind States, EPA set each State's budgets by determining the emission reductions that would be achieved if the State adopted the emission controls available at "specific cost per ton thresholds." *Id.* at 48248; *see also id.* at 48258. For

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2014 budgets, EPA split States into two groups for SO_2, using \$2,300/ton for Group 1 States and \$500/ton for Group 2 States. *Id.* at 48252. EPA based the 2014 NO_X budgets on the \$500/ton threshold. *Id.* at 48257.

This approach led to overcontrol. First, EPA failed to consider whether less-restrictive emission budgets would achieve attainment. Industry/Labor Br. 31–34 (Doc.1364190). EPA never considered whether attainment could be achieved at cost thresholds below \$500/ton, 76 FR at 48256–58, despite evidence that attainment could be achieved at lower cost thresholds, JA1062–69, 1374.

Second, EPA did not adjust the 2014 budgets to account for the fact that it projected that air quality would improve substantially between 2012 and 2014 *even without any good-neighbor emission reductions. See supra* p. 5. In fact, EPA projected that many areas that were expected to have air-quality problems in 2012 would achieve air quality *superior* to the NAAQS by 2014 even without the Transport Rule or CAIR. *Id.*

Petitioners thus have a substantial probability of demonstrating that EPA's approach, in fact, resulted in overcontrol. The most vivid examples are as follows.[3]

Overcontrol as to ozone. EPA imposed emission budgets on 10 upwind States—Florida, Maryland, New Jersey, New York, North Carolina, Ohio,

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[3] Although EPA has vaguely suggested these overcontrol arguments may have been waived, EPA Mot. to Govern 9–11 (Doc.1500830), that is not the case, *see* Luminant Resp. 6–9 (Doc.1501970). In fact, consideration of these as-applied challenges is required by the Supreme Court's mandate, *id.* at 6 n.3, and, moreover, EPA has waived its waiver argument, Industry/Labor Mot. to Govern Reply 7 (Doc.1504905).

Pennsylvania, South Carolina, Virginia, and West Virginia—that were linked

exclusively to locations that EPA projected would attain the ozone NAAQS in 2014

without any good-neighbor obligations.[4] For example, EPA linked Florida to only two

downwind locations, both in Harris, TX, 76 FR at 48246 (tbl.V.D-9), but EPA

projected that those areas would have no attainment or maintenance issues in 2014—

even without the Transport Rule or CAIR, *see* JA2575–76.[5]

Overcontrol as to South Carolina for PM$_{2.5}$. South Carolina was regulated

for PM$_{2.5}$ solely because EPA found it was linked to projected annual PM$_{2.5}$ attainment

problems at Fulton, GA. 76 FR at 48241 (tbl.V.D-2). EPA projected, however, that

Fulton would have air quality superior to the relevant NAAQS in 2014 without any

good-neighbor emission reductions. JA2584, 2959–60 (2014 "base case" projections).

Overcontrol as to Texas for PM$_{2.5}$. EPA has never disputed that it

overcontrolled Texas, because it cannot. *See* Luminant Summ. Vac. Mot. 6–12

(Doc.1504643). The only downwind location to which Texas was linked for PM$_{2.5}$ was

Madison, IL. 76 FR at 48241–44 (tbls.V.D-2–3, 5–6). EPA's data show that Madison

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[4] These upwind States were linked exclusively to one or more of the following
locations: Fairfield and New Haven, CT; Harford, MD; Allegan, MI; and Harris, TX.
76 FR at 48246 (tbl.V.D-9). EPA projected that none of these areas would have
attainment or maintenance concerns in 2014 even in the absence of good-neighbor
emission reductions. *See* JA2550, 2560, 2561, 2575–76 (2014 "base case" projections).

[5] EPA also overcontrolled Texas as to ozone. Texas was linked to ozone problems in
only two areas (East Baton Rouge and Allegan), 76 FR at 48246 (tbls.V.D-8–9), which
both attained the ozone NAAQS under CAIR. *See* 75 FR 58312 (Sept. 24, 2010); 75
FR 54778 (Sept. 9, 2010). *See also* Luminant Summ. Vac. Mot. 12 (Doc.1504643).

was projected to achieve $PM_{2.5}$ air quality far superior to the NAAQS under the Transport Rule. JA2964–65. In fact, Madison attained the NAAQS at the *higher* emission levels that occurred under CAIR. *Compare* 76 FR 29652, 29654 (May 23, 2011) (showing Madison attained the $PM_{2.5}$ NAAQS), *with* 76 FR 70091, 70099 (Nov. 10, 2011) (Transport Rule "mandates even greater reductions than have already occurred under CAIR"). Where attainment has been achieved at higher emission levels, further emission reductions are unnecessary to ensure attainment. Indeed, EPA's data show that Madison would have air quality right at the NAAQS without any good-neighbor obligations. JA2586, 2615 (2014 "base case" projections). These projections confirm that Madison would achieve attainment with only modest upwind emission-reduction obligations. *See infra* n.6 (EPA data confirming Madison would attain the relevant NAAQS with lower-cost emission controls).

Overcontrol of Group 2 States. EPA set SO_2 budgets for Group 2 States, and NO_x budgets for all states, at $500/ton of emissions removed. But, as noted, EPA did not consider whether attainment would be achieved at lower cost thresholds despite evidence demonstrating this to be the case. As to SO_2, EPA offered no reason for its refusal, and as to NO_x, it stated only that it "did not find cost thresholds lower than $500/ton … to be reasonable" because they might cause some sources "to stop operating existing pollution control equipment." 76 FR at 48257.

Although EPA disregarded this critical statutory issue when setting final emission budgets, it did consider the impact of lower cost thresholds when it

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proposed the Transport Rule. EPA's air-quality data from the proposal stage show

that Alabama, Georgia, South Carolina, and Texas are linked exclusively to downwind

locations that would attain and maintain the $PM_{2.5}$ NAAQS even if cost thresholds

lower than \$500/ton were used to determine upwind emission budgets.[6]

2.   EPA regulated insignificant contributions.

EPA also regulated "insignificant" emissions in violation of the limits on its

statutory authority. As noted, the Supreme Court held that EPA cannot "demand

reductions that would drive an upwind State's contribution to every downwind State

to which it is linked below one percent of the relevant NAAQS." *EME Homer*, 134 S.

Ct. at 1608. Having determined that contributions of less than 1% of the NAAQS

were *in*significant, EPA could not ignore that finding when setting emission budgets.

The Supreme Court thus remanded to this Court to determine the extent to which

EPA had transgressed this limit on its authority. *Id.* at 1608–10.

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[6] EPA linked these four States to certain locations that were projected to have attainment or maintenance problems in 2012 without good-neighbor emission reductions. *See* 76 FR at 48241–44 (tbls.V.D-2–3, 5–6). However, at the notice stage, EPA generated tables showing the extent of reduction in upwind contribution to downwind nonattainment areas that would occur if States adopted emission controls at varying cost increments between \$0 and \$500/ton. Air Quality TSD (Notice) 69–70 (tbl.3-1), 75–78 (tbl.3-4) (July 2010) (http://www.epa.gov/airtransport/CSAPR /pdfs/TSD_analysis_to_quantify_significant_contribution_7-8-10.pdf). Those tables show that the downwind locations to which Alabama, Georgia, South Carolina, and Texas were linked would attain the NAAQS with SO_2 controls costing less than \$500/ton. *Id.* For example, Texas was linked only to Madison, IL, 76 FR at 48241–44 (tbls.V.D-2–3, 5–6), but EPA's data projected Madison would attain the NAAQS if all States adopted \$100/ton cost controls for SO_2, Air Quality TSD (Notice) 69, 75.

As explained in Luminant's motion for summary vacatur (at 12–15) (Doc.1504643), EPA clearly did so with respect to Texas. EPA found that Texas's maximum contribution was only slightly above the "insignificance" threshold for the PM$_{2.5}$ NAAQS, yet required the State to make substantial emission reductions. *See* 76 FR at 48240 (tbl.V.D-1) (showing Texas's maximum contribution of only 0.03 μg/m^3 above the "insignificance" threshold of 0.15 μg/m^3); *id.* at 48261–62 (tbl.VI.D-3) (requiring emission reductions). The same analysis shows EPA exceeded its authority with respect to South Carolina for ozone. *See id.* at 48245 (tbl.V.D-7) (showing South Carolina maximum contribution of only 0.1 ppb above the "insignificance" threshold of 0.8 ppb); *id.* at 48262–63 (tbl.VI.D-4) (requiring emission reductions).

3.   Industry/Labor petitioners' unaddressed arguments.

As noted, a number of challenges in the Industry/Labor petitioners' opening brief remain unresolved: (i) whether EPA arbitrarily failed to consider lower cost thresholds when setting emission budgets, Industry/Labor Br. 31–34 (Doc.1364190); (ii) whether EPA arbitrarily adopted a "one-way" ratchet when setting budgets, *id.* at 34–36; (iii) whether EPA's reliance on flawed air-quality modeling was arbitrary and capricious, *id.* at 37–47; and (iv) whether EPA's use of the Integrated Planning Model to set emission budgets was arbitrary and capricious, *id.* at 47–52.

The Industry/Labor petitioners have a substantial probability of success on these arguments for the reasons set forth in their prior briefing. Indeed, the Supreme Court, by confirming that EPA has a statutory obligation to avoid overcontrol,

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affirmed the essential predicate of the argument that EPA arbitrarily failed to consider lower cost thresholds. *See supra* p. 11. It also confirmed that EPA could not ignore its air-quality projections that showed substantial downwind attainment in 2014 without any good-neighbor controls. *See supra* pp. 11–12.

B.   Petitioners Would Suffer Irreparable Harm If The Transport Rule Became Effective In 2015.

EPA's proposal to implement the Transport Rule in 2015 would require some petitioners to make deep emission reductions through costly changes at generating units. These harms are irreparable because the costs cannot be recovered even if petitioners prevail on the merits. *See Armour & Co. v. Freeman*, 304 F.2d 404, 406 (D.C. Cir. 1962) ("loss of profits which could never be recaptured" is irreparable harm); *Iowa Utils. Bd. v. FCC*, 109 F.3d 418, 426 (8th Cir. 1996) (inability to recover damages from government renders economic losses irreparable harm).[7]

Luminant's situation is a good example. While EPA is correct that Luminant has taken steps to reduce emissions during the pendency of the stay, EPA's proposal to implement the Transport Rule in 2015 would require further, *unlawful* emission reductions that would impose substantial, unrecoverable costs on Luminant. *See generally* Goering Decl. (Ex. 1). These unrecoverable costs are more than sufficient to

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[7] EPA has wrongly contended that financial loss is irreparable only when it threatens the "'very existence'" of the company. EPA Opp. 17 (Doc.1333987) (citing *Wisc. Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985)). But that is so only when financial loss would later be *recoverable*. *Wisc. Gas*, 758 F.2d at 674 ("Recoverable monetary loss may constitute irreparable harm only where the loss threatens the very existence of the movant's business."); *accord Iowa Utils.*, 109 F.3d at 426.

support preserving the status quo in light of petitioners' overwhelming probability of success on the merits. *See Aamer v. Obama*, 742 F.3d 1023, 1043–44 (D.C. Cir. 2014).

EPA's own analysis confirms that Texas sources, including Luminant, would be harmed by a 2015 implementation date. According to EPA, Texas's Phase 1 SO_2 budget is 20% lower than the State's predicted emissions, EPA Mot., Harvey Decl. at 11, tbl.2, and the substantial allowance shortfall is borne *almost entirely* by Luminant, Goering Decl. ¶¶3, 19. Luminant would have a substantial shortfall of NO_x allowances as well. *Id.* ¶19. Luminant would incur substantial unrecoverable costs to close this gap. *Id.* ¶22. Because it operates in a competitive market, even if Luminant were to prevail, these expenditures could never be recovered. *Id.* ¶¶2, 22.

ALA's proposed implementation schedule would exacerbate petitioners' injury. First, the more restrictive Phase 2 budgets ALA seeks to have imposed on January 1, 2015, would decrease the availability of allowances that could be traded. *Id.* ¶23. Second, by having variability limits apply on January 1, 2015, ALA would diminish the likelihood that a trading market will develop. *Id.* Indeed, EPA, quite properly, delayed application of the variability limits for this very reason. *See* 77 FR at 10331.

Moreover, as explained in the Declaration of James Marchetti (Ex. 2), ALA's speculation that it is feasible to achieve the Phase 2 reductions by January 1, 2015, is unfounded. Unlike ALA's declaration, Mr. Marchetti's declaration is based on information directly from owners and operators of most of the units discussed in

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ALA's declaration. Marchetti Decl. ¶7. The best available data show that affected

parties cannot meet Phase 2 requirements by January 1, 2015. *Id.* ¶¶16–35.

C.   The Equities Favor Maintaining The Stay.

Maintaining the stay will not harm the public health. EPA concedes that

aggregate emissions are substantially *lower* under the stay with CAIR's budgets in place

than Phase 1 of the Transport Rule would allow if implemented. *See, e.g.*, EPA Mot.

18. EPA speculates this "could change" because the emission reductions were due "in

part" to non-regulatory factors, but it *does not even assert* that emissions will exceed the

Transport Rule's Phase 1 budgets if the stay continues for the limited period needed

for remand proceedings. *Id.* at 10.[8]

Instead, EPA's argument for lifting the stay is premised on asserted benefits

from the Transport Rule's Phase 2 budgets. *Id.* at 11 ("In the future, sources will need

to achieve additional emissions reductions to achieve the Rule's Phase 2 requirements

and fully realize the Rule's benefits."). But under EPA's own proposal, Phase 2

budgets would not go into effect until 2017, and EPA makes no claim that imposing

Phase 1 budgets would have any significant environmental benefits.

Nor could it. As a result of the reductions "already achieved," *id.* at 10, EPA

has reported that virtually all downwind locations in the eastern United States attained

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[8] Tellingly, while EPA's Harvey claims that "emissions data for the first quarter of 2014 show an increase in emissions of pollutants controlled under Transport Rule programs from the first quarter 2013 levels," EPA Mot., Harvey Decl. ¶49, he does *not* claim that 2014 emissions exceed the Transport Rule's Phase 1 budgets.

the NAAQS addressed in the Transport Rule by 2011. *E.g.*, EPA, *Progress Report 2011: Environmental and Health Results Report* 12, 14 (2013). EPA found that CAIR-related reductions were a "significant contributor to these improvements." *Id.* at 12.[9] Relatedly, the State/Local petitioners demonstrate in detail that the downwind locations of concern in the Transport Rule are overwhelmingly attaining and maintaining the applicable NAAQS under CAIR. *See* State/Local Opp. Part II.B.

By contrast, allowing the Transport Rule to take effect now would cause disruption in the (likely) event that the Rule is again struck down. Reinstituting CAIR at that point would be much more complicated than simply maintaining CAIR during the limited pendency of this appeal (which all agree should proceed quickly). For example, "banked" CAIR allowances would need to be returned to their owners and new CAIR allowances distributed. It would also almost certainly result in regulated entities having purchased Transport Rule allowances that could no longer be used.

EPA's primary concern seems to be "getting on with the replacement of CAIR," EPA Mot. 12–13, regardless of whether CAIR's replacement is legal and regardless of the resulting disruption and wasted resources. Lifting the stay now, while

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[9] ALA seeks to impose Phase 2 budgets because, according to ALA, EPA found the Phase 2 reductions are necessary to prevent thousands of deaths. ALA Resp. 9. This argument is based on a misleading and irrelevant comparison. EPA calculated the Transport Rule's benefits assuming *no* good-neighbor restrictions were in place. EPA's analysis, and thus ALA's argument, ignores CAIR, which is in place and has produced widespread attainment—a level of air quality that is sufficient "to protect the public health" with "an adequate margin of safety." 42 U.S.C. §7409(b)(1).

the Rule's legality remains unresolved, would not produce "regulatory certainty," *id.* at 13, but only litigation advantage for EPA. Petitioners expect that EPA would argue that, if the stay is lifted and the Transport Rule becomes effective, CAIR cannot be reinstituted at the end of this litigation. But that real possibility provides a further reason for maintaining the stay, because allowing the Transport Rule to take effect may ultimately dictate petitioners' ability to obtain effective relief.

CONCLUSION

For these reasons, the Court should deny the motions to lift the stay.

Dated: July 31, 2014   Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that on July 31, 2014, I caused the foregoing Opposition to be

served on all registered counsel through the Court's CM/ECF system.

<div align="right">

/s/ Peter D. Keisler
Peter D. Keisler
Counsel for Luminant Petitioners

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EXHIBIT 1

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Luminant Generation Company LLC, et al.	)	
	)	
Petitioners,	)	
	)	
v.	)	Case No. 11-1315
	)	
Environmental Protection Agency, et al.	)	
	)	
Respondents.	)	
	)	

Declaration of Matthew Goering

1.   I am vice president of fuel and emissions strategy for Luminant Energy Company LLC, a

wholesale marketing and trading operation. I will use "Luminant" in this declaration to

refer to all of the Luminant entities that are parties in this matter. I make this declaration

in support of Industry/Labor Petitioners' opposition to the "Respondents' Motion to Lift

the Stay Entered on December 30, 2011" of the Cross-State Air Pollution Rule

("Transport Rule"). *See* U.S. Environmental Protection Agency, (EPA) Federal

Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and

Correction of SIP Approvals, 76 Fed. Reg. 48208 (Aug. 8, 2011).[1] In addition to

reviewing EPA's motion, I have also reviewed and analyzed the supporting Declaration

of Reid Harvey, which explains how EPA proposes to implement the Transport Rule

should the Court grant EPA's motion. I have also reviewed the declaration filed by

Ranajit Sahu that was filed on behalf of the American Lung Association and several other

groups (collectively, "ALA") in response to EPA's motion to lift the stay. This

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[1] Unless otherwise specified, references to the Transport Rule include corrections to that rule, including corrections to the emissions budgets for Texas. *See* 77 Fed. Reg. 10324 (Feb. 21, 2012); 77 Fed. Reg. 34830 (June 12, 2012).

declaration is based on my personal knowledge and on analyses conducted by my staff and reviewed by me. All opinions are based on my education, training, and experience in the power generation industry.

Summary of Harm

2.   The purpose of this declaration is to demonstrate that, were the Transport Rule to go into effect on January 1, 2015, Luminant would suffer irreparable harm as a result. In brief, the emissions budgets imposed by the Transport Rule for Texas for sulfur dioxide ("SO_2") and annual and seasonal nitrogen oxides ("NO_x") will not provide Luminant with sufficient emissions allowances to operate its plants without alterations, including changes to existing pollution controls and fuel substitution, and the acquisition of additional allowances through trading. Luminant expects that the **single-year** cost to comply with the Transport Rule's limits would be **$17-25 million** for 2015. Because Luminant operates in a competitive, deregulated market, it cannot simply ask the Public Utility Commission of Texas to increase its rates so as to recover these extra expenditures; nor can it recover them from EPA. Similar harms would continue to impact Luminant beyond 2015 for so long as the current Transport Rule remains in effect, should the stay be lifted. In contrast, none of these harms would occur were Luminant to continue to comply with the Clean Air Interstate Rule ("CAIR") until EPA can promulgate a lawful successor to the Transport Rule.

3.   Mr. Harvey's declaration illustrates why the harm to Luminant will be so significant. As Mr. Harvey states, Texas is unique among all of the 23 states subject to the Transport Rule's SO_2 provisions in that its current emission levels are well above the budget limits that EPA seeks to impose in less than 6 months. Harvey Decl. at Tables 1 & 2. Imposing the Transport Rule now would require Texas—but no other state—to reduce SO_2

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emissions by approximately 20% from 2013 levels. Harvey Decl. at Table 2. Moreover, lifting the stay falls even harder on Luminant, because Luminant is entitled to only a share of the state's budget and assurance level, and its share reflects an even greater proportionate deficit of SO_2 allowances.

Background

4.   I graduated from the University of Kansas with a bachelor's degree in mechanical engineering in 1991. I also earned a MBA degree in finance from the Wharton School at the University of Pennsylvania in 1997.

5.   I have been employed by the company, including its predecessor TXU, for over 12 years. Prior to my current position, I oversaw fuels management for TXU Power (now Luminant Generation) as well as coal, emissions, crude, and fuel-oil trading for TXU Portfolio Management (now Luminant Energy).

6.   Luminant is the largest competitive power generation company in Texas. Luminant has over 15,400 megawatts ("MW") of generation capacity including coal-fueled, gas-fueled, and nuclear units.   This generation portfolio includes 8,017 MW fueled by lignite and subbituminous coal at twelve coal-fueled electric generating units ("EGUs") at five generating plants in Texas. Luminant contributes approximately 22% of the electricity dispatched to Texas consumers and businesses by the Electric Reliability Council of Texas ("ERCOT"), the independent system operator that manages Texas's competitive power market that serves the majority of the state. Luminant develops and operates generation units using a variety of fuel sources, including coal, in order to meet the growing demand for electricity in Texas.

7.   I am part of a cross-functional team at Luminant studying all aspects of the Transport Rule and the company's compliance options in light of the U.S. Supreme Court decision

that remanded the case to the D.C. Circuit Court of Appeals and the EPA's subsequent

motion to lift the stay that has been in effect since December 30, 2011. This declaration

is based on ordinary-course business analysis that Luminant has conducted to understand

how its operations would be impacted if the Transport Rule were to be put into effect.

During the stay, industry (including Luminant) has continued to comply with CAIR in

lieu of the Transport Rule.

8.   The EPA's motion to lift the stay seeks to have a rule that was originally scheduled to

become effective January 1, 2012, instead become effective January 1, 2015, less than 6

months from now. The Transport Rule contains very detailed provisions regarding

emissions in 2012 and later years. Many of these provisions were issued in rules not

before the Court in this case. Further, because three of the initial years will have passed

while the Transport Rule was stayed, EPA has requested that the Court impose the

Transport Rule as if it were 2012, not 2015. It is not clear to Luminant whether the Court

could or would do so, especially with respect to deadlines and provisions that were issued

in rules not before the Court in this case. EPA has also stated that it would conduct one

or more rulemakings if the Court lifts the stay before EPA could implement the Transport

Rule in 2015. But, EPA has not provided a schedule for those rulemakings, which

themselves may be subject to challenge.

9.   Thus, there is much uncertainty in what EPA's motion is proposing, making it difficult to

predict exactly how a 2015 effective date would impact Luminant. For purposes of this

declaration, my analyses focus on Luminant's compliance options for 2015 under the

Transport Rule, both as the rule is presently written (i.e., with no tolling or further

rulemaking) and with the three years of tolling requested by EPA and assuming that the

additional rulemakings EPA says it would undertake are indeed undertaken and completed by January 1, 2015. My team, under my supervision, analyzed the Texas and other states' emissions budgets for emissions of SO_2 and annual and seasonal NO_x, the potential availability of trading allowances to offset otherwise required emission reductions, and the full range of operational changes that may be possible at Luminant's plants, including everything from derating or shutting down plants to installing or modifying pollution control equipment on short notice to switching types of fuels, including the intersection of other environmental rules and requirements that apply to Luminant's plants such as the Mercury and Air Toxics Standards and specific unit permit requirements. Due to the very short lead time Luminant has before January 1, 2015, Luminant could not explore long-term options that may provide lasting, multi-year benefits. Exploring such options requires both regulatory certainty (as to long-term compliance requirements) and sufficient lead time for consideration, analysis, planning and possibly permitting of potentially large, multi-year, capital-intensive projects.

Steps Taken by Luminant Since 2011 to Reduce Emissions

10. Before discussing the harms associated with lifting the stay currently in place, I first note that Luminant has not sat on its hands since the Transport Rule was stayed at the end of 2011. In support of its original motion for a stay in 2011, for example, Luminant estimated that its fleet-wide SO_2 emissions for 2012 would be almost 240,000 tons. Now, a mere three years later, Luminant estimates that its total SO_2 emissions for 2015 will be almost 85,000 tons lower (see the table below – 155,000 tons), which is a 35% reduction. The reductions are due to a variety of steps taken by Luminant, including scrubber upgrades at several plants, improved scrubber utilization rates, some fuel switching from lignite to lower sulfur coal from the Powder River Basin area of

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Wyoming, and, for a few units, anticipated seasonal operations. Some reductions—especially in 2012—also relate to natural gas prices. Nevertheless, as Mr. Harvey's declaration states, EPA is still seeking significant additional SO_2 reductions from Texas over 2013 levels, and those reductions, if required in 2015, would, as before, cause Luminant irreparable harm. Harvey Decl. at Table 2.

The Transport Rule's Allowance System for SO_2 and NO_x Emissions

11.   EPA seeks to lift the stay and impose stringent annual SO_2 and NO_x emission limitations on Texas starting on January 1, 2015, due to concerns about the attainment status of one "downwind" county in Illinois. It would also impose stringent seasonal NO_x emission limitations starting May 1, 2015, due to concerns about impacts in two other downwind locations located in Michigan and Louisiana. EPA would impose these limits regardless of the significant improvements in downwind air quality at the three locations in question under CAIR that essentially negate the need for the Transport Rule's limitations.

12.   The Transport Rule's limitations are expressed in emission budgets that are applicable to EGUs such as those operated by Luminant. The rule includes four trading programs – one for annual SO_2 emissions (subdivided into two groups) and one each for seasonal and annual NO_x emissions – which allow for limited trading of "allowances" from sources in Texas and other states. The SO_2 trading program is further divided among "group 1" and "group 2" states. Texas is a group 2 state and may only trade with other group 2 states for the SO_2 trading program. Trading allowances essentially represent a ton of emissions of SO_2 or NO_x and are used to demonstrate compliance by offsetting emissions that are not reduced through other means.

13.   EPA assigned each state in the emissions trading programs an overall budget for allowances in the programs in which they participate. The allowances in a state's budget

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are further allocated among the sources in that state based on EPA's modeling

assumptions. Had the Transport Rule not been stayed in December 2011, EPA would

have, under a subsequent "Revisions Rule," 77 Fed. Reg. 10324 (Feb. 21, 2012),

permitted industry to engage in unlimited allowance trading to comply with the

applicable limits in 2012 and 2013 to achieve compliance with the Transport Rule.

However, as I understand it, that error corrections rule is not before the Court in this case

and is being challenged in separate case that has been stayed pending the conclusion of

this case. Even if the Revisions Rule is deemed effective on January 1, 2015, as written,

it still limits the amount of trading from 2014 forward. (EPA refers to these limits as

"variability limits"). EPA seems to be asking the Court to delay the variability limits by

three years by changing the dates in the Revisions Rule, but I understand that the

Revisions Rule is not before the Court in this case and EPA has not issued a rulemaking

proposal to change the effective date of those variability limits.[2]

14.   The post-2013 limits on allowance trading restrict the number of allowances that can be

acquired by any given company to that company's allocated share of the state's

"variability limit" established by EPA. Variability limits allow a state to emit a certain

number of tons in excess of its budgets. However, if a state's emissions exceed its state

budgets plus variability limits (the sum of which EPA calls "assurance levels") for SO_2,

annual NO_x, or seasonal NO_x, each individual source with emissions above its pro rata

portion of the assurance level would be penalized by being required to surrender three

allowances for every ton of its excess emissions. Thus, industry's overall harm would

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[2] These limitations are found in the current and effective version of 40 C.F.R. §§ 97.410(b), 97.510, 97.610(b), 97.710(b).

increase, and the flexibility that EPA intended for the first two years of the program would be lost, were the Transport Rule to become effective in 2015 as written without adjustments being made to the applicability of the assurance levels.

15.   The increased harms I referred to in the prior paragraph would be all but certain if ALA's proposed implementation of the Transport Rule were adopted. As I understand it, ALA is proposing that there would be no "tolling" of the Transport Rule's compliance deadlines and that regulated sources would be required to meet the Rule's "Phase 2" budgets on January 1, 2015. For many states, the Transport Rule's Phase 2 budgets are more restrictive than their Phase 1 budgets and, even for those states that have the same budgets, there would be fewer allowances available for trading if Phase 2 budgets were implemented on January 1, 2015. I further understand that ALA would have the variability limits that restrict allowance trading apply on January 1, 2015.

**The Transport Rule Provides Insufficient Allowances for
Luminant Plants to Operate Normally in 2015**

16.   Luminant operates both coal-fueled and gas-fueled plants that emit SO_2 and NO_x. Generally, the Transport Rule's SO_2 and NO_x limitations are the constraining factor for the coal plants, and its NO_x limitations are the constraining factor at the gas plants.

17.   In his declaration, Mr. Harvey focuses on state budgets and assurance levels, but not on individual sources or companies. As I noted above, for example, the Texas SO_2 budgets and the assurance level are insufficient to meet the state's needs for allowances. But much more critically, it is the allocation of those budgets among individual sources that determine a company's compliance obligations. Even where a state may have a "surplus" of allowances, individual sources may not hold sufficient allowances to operate normally.

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18.   Ranajit Sahu makes this same error in his analysis. In fact, he assumes for example that

there is **no** shortage of annul NOx allowances in Texas, yet I demonstrate below that

Luminant faces exactly that deficit. He also suggests that some so-called "cleaner"

sources will be coming on-line in Texas, and he seems to imply that this will materially

impact the compliance obligations of individual sources. As noted, the fact that other

generating sources may come on line in 2015 does not change the fact that, under EPA's

current distribution of allowances, Luminant would not be allocated sufficient allowances

to continue normal operations in 2015. Further, dispatch of wind-generation is very

irregular because those sources are often not generating power when they can be

economically dispatched. In any event, my analysis is based on the best estimates

available of the expected mix of generation and dispatch for 2015 in Texas, including the

extent to which Luminant facilities would be dispatched.

19.   Luminant's allocated share of allowances for SO_2, and seasonal NO_x for 2015 is

insufficient to allow continued operation of the existing fleet of generation assets without

causing significant harm as discussed in more detail below. Neither Mr. Harvey nor Dr.

Sahu consider the allocations to specific companies and, contrary to their suggestions, if

the Transport Rule were to go into effect, Luminant would have a substantial shortfall of

emissions allowances. Table 1 summarizes the shortfall that Luminant expects to see for

its own operations in 2015. As noted, this is based on Luminant's ordinary-course

business analysis of expected operations in 2015.

Table 1: Estimated 2015 Allowance Shortfalls (exclusive of Oak Grove 2 which is considered a new unit.)

	Group 2 SO_2	Annual NO_x	Seasonal NO_x
Luminant's Projected Emissions (tons)	155,000	31,000	15,800
Luminant's Share of Allowances	95,201	32,048	14,998
Luminant's Projected Allowance Shortfall	59,799	(1,048)	802

20.   Based on our analysis of the potential SO_2 and NO_x (annual and seasonal) trading

markets, Luminant does not believe that a significant market would exist in 2015 for

group 2 SO_2 allowances. First, Texas itself will not have sufficient allowances to cover

estimated state-wide SO_2 emissions from Texas EGUs, leaving no SO_2 allowances left

over for trading among generators within the state. Second, Luminant expects companies

to approach this new trading market conservatively. This is particularly true for regulated

utilities, which have little economic incentive to sell their allowances quickly,

particularly since allowances can be used to demonstrate compliance in future years.

Thus, while the seven group 2 states collectively may have a surplus of SO_2 allowances

available for trading, Luminant has no guarantee that any individual company would be

willing to sell its allowances at a reasonable price or at all. Projections of actual

emissions are not always accurate; therefore, companies presumably would not part with

their allowances until they are confident they will not need them, which may not be until

late in the year, following the end of the compliance period, or after the surrender

deadline; or they may choose to bank the allowances for future company use. Companies

are also competitive, and those with excess allowances may wish to retain them for a

perceived competitive advantage. I believe this would be true even if the three years of

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tolling requested by EPA were granted, although the odds are better for a market to develop in that scenario. As a prudent manager of risk, Luminant could not wait indefinitely for a market to develop and risk noncompliance with the Transport Rule.

21.   In contrast, Luminant predicts that a limited market may develop for trading annual and seasonal NO_x allowances, largely because of the larger size of the marketplace (23 states for annual NO_x allowances and 25 states for seasonal NO_x allowances). This result is even more likely if the three years of tolling requested by EPA were granted.
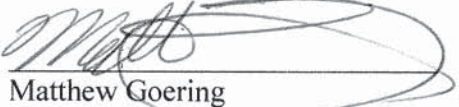
Harms Caused by the Transport Rule's SO_2 and NO_x Budgets

22.   As noted, in order to comply with the Transport Rule in 2015 (with or without the three years of tolling and rule changes by EPA), Luminant expects that it would have to reduce its overall SO_2 emissions from an estimated 155,000 tons to 95,201 tons. To achieve those reductions on short notice (*i.e.*, in a matter of months, without the years of lead time necessary to design, permit, fabricate, install, test, and commence operating major new pollution control equipment), Luminant would have to take the following actions: immediately increase operation and maintenance expenditures to procure additional consumables for use at multiple plants to enable scrubber units to remove additional SO_2 emissions; increase purchases of lower sulfur Powder River Basin coal; and/or attempt to acquire both SO_2 and NO_x allowances, to the extent a market develops and the price of the allowances is cost-effective in comparison to other options (such as more scrubbing and more fuel switching). Assuming some amount of cost-effective SO_2 allowances are available, I estimate that the total estimated harm for 2015 would be **$17-22 million**. If cost-effective SO_2 allowances are not available, or if no market develops at all, then the total harm is likely to be approximately **$25 million**. Again, this harm is irreparable, as

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Luminant cannot recover these expenditures from ratepayers or from the EPA, nor are these long-term improvements that would have lasting benefit and value for the company.

23.   If ALA's proposed approach were adopted instead of EPA's approach, Luminant's costs would very likely fall on the high side of the range that I have estimated for several reasons. Two group 2 states, Alabama and Georgia, have more restrictive Phase 2 budgets relative to Phase 1. That will decrease the pool of SO_2 emissions allowances potentially available for trading. In addition, ALA would have variability limits apply immediately. I understand EPA delayed the variability limits in an effort to allow allowance trading to develop. ALA's proposal thus increases the likelihood that allowances will not be available to Luminant or will be more costly than Luminant has anticipated.

I, Matthew Goering, declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed this 28th day of July, 2014.

Matthew Goering

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EXHIBIT 2

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA

EME HOMER CITY GENERATION, L.P.,	)	
	)	
Petitioner,	)	
	)	
v.	)	No. 11-1302 (and
	)	consolidated cases)
UNITED STATES ENVIRONMENTAL	)	
PROTECTION AGENCY, *et al.*,	)	
	)	(COMPLEX)
Respondents,	)	
	)	

DECLARATION OF JAMES MARCHETTI

1.   I, James Marchetti, under penalty of perjury, affirm and declare that the following statements are true and correct to the best of my knowledge and belief and that they are based upon my own personal knowledge, on information gathered from the sources described herein, and on information contained in the documents and other records cited herein.

2.   I am an economist, with masters degrees from both Rutgers University and Boston University. As a consultant, I have over 35 years of experience in performing various kinds of environmental policy, regional and environmental economic analyses for a variety of companies, including many in the electric generation industry.

3.   I have completed numerous strategic analyses related to environmental policy and compliance. I co-developed the *Emission-Economic Modeling System (EEMS)* and maintain its database. *EEMS* and its database have been used by electric utilities to evaluate the economic and technological implications of state and federal multi-pollutant regulatory proposals and policies.

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4.   I have conducted numerous technical analyses of EPA's Cross-State Air Pollution Rule ("CSAPR" or the "Transport Rule") for utilities, trade associations and others, some of which are listed below:

- For a Georgia utility, I evaluated its sulfur dioxide ("SO2") and nitrogen oxide ("NOx") emission exposure and allowance banks for several EPA rules, including CSAPR, and I assisted that utility in providing comments to EPA on several notices of data availability related to the Transport Rule. I also evaluated the final Transport Rule and proposed revisions to that rule, focusing on how these proposed revisions affect Georgia state budgets and unit allowance allocations.

- For a group of Kansas utilities, I estimated the availability of CSAPR SO2 (Group 2) allowances, annual NOx allowances, and seasonal NOx allowances for the years 2012 to 2014.

- For an Indiana utility, I determined a compliance plan under the Transport Rule, the Mercury and Air Toxics Standards ("MATS") Rule, and hypothetical Transport Rules II and III. This analysis was submitted as a supporting document to the Indiana Public Service Commission.

- For a trade association, I developed two specific CSAPR databases: (i) a database that illustrated 2012 and 2014 SO2 (Group 1 and Group 2) budgets, annual NOx budgets, and seasonal NOx budgets for the final Transport Rule and proposed revisions to that rule; and (ii) a database focused on a specific group of units to evaluate their 2012 to 2014 allocations of SO2, NOx annual and NOx seasonal allowances under CSAPR.

- For the Utility Air Regulatory Group ("UARG"), I used the *EEMS* database to identify EPA modeling errors in CSAPR. This analysis was submitted to EPA by UARG in support of UARG's petition for reconsideration of CSAPR.

- For a trade association, I developed a series of databases related to emission exposure and costs under both the proposed and the final versions of the Transport Rule.

5.   This declaration is filed in support of the Joint Opposition of Industry/Labor Petitioners to Motions to Lift the Stay, to be filed in the above-captioned case on July 31, 2014. I was retained by petitioner UARG to conduct the analysis described in this declaration.

6.   The purpose of this declaration is to provide comments on and corrections to statements made in the Declaration of Ranajit Sahu ("Sahu Dec."), which was filed in support of the Response of Public Health Intervenors to Respondents' Motion to Lift the Stay Entered on December 30, 2011 Combined with Motion for Alternative Relief. In his declaration, Dr. Sahu examined past and current SO_2 emissions from and emission rates of electric generating units ("EGUs") in seven states (Indiana, Kentucky, Michigan, Ohio, Pennsylvania, Texas, and Wisconsin) and EGUs' NO_x emission and emission rates in one state (Missouri). Following that examination, Dr. Sahu concluded that the Transport Rule's Phase 2 emission budgets for NO_x and SO_2 are achievable by early 2015. See Sahu Dec. at ¶¶ 5, 11, and 17.

7.   In preparing this declaration, I not only reviewed Dr. Sahu's emission calculation methodology and assumptions regarding emission control technology deployment schedules and emission rates, but also contacted individuals familiar with emission units evaluated by Dr. Sahu. In addition, I consulted publicly available information concerning the operations of relevant EGUs, and I reviewed information concerning the capabilities of emission control equipment. Based on my comprehensive review and the information available to me, I believe the information that I present in this declaration correctly represents how these EGUs can be expected to operate in the next few years.

Methodology in the Sahu Declaration

8.   In his analysis, Dr. Sahu makes several key assumptions. First, Dr. Sahu "focus[es] . . . on the assurance levels" established in Phase 2 of the Transport Rule – *rather than on the actual emission budgets established by the Rule* – because "assurance levels . . . place a firm cap on emissions from EGUs in each of the covered states." Sahu Dec. ¶6. In addition, Dr. Sahu assumes that it is reasonable to use one year of emissions and emission rate data and to base predictions of future-year compliance on that narrow snapshot of data. See, for example, Sahu

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Dec. ¶14 ("I assume for the purpose of this analysis that EGUs without SCR [selective catalytic reduction] controls [for NOx emissions] continue operating at their 2013 NOx emission rates"). Because a number of Dr. Sahu's methodological assumptions are flawed, his reliance on them has led him to draw erroneous conclusions as to whether, and to what extent, regulated sources in affected states will be able to comply with Phase 2 of the Transport Rule by early 2015.

9.   Dr. Sahu's initial premise is that the assurance levels provide the operative frame of analysis. For that premise to work, by the beginning of 2015, EGUs in a state that needs allowances in 2015 would have to be able to get those allowances from EGUs in other states – states that would not need the extra allowances for their own EGUs. To evaluate the reasonableness of this assumption, I compared the actual year-2013 SO2 emissions of EGUs in Group 1 states with those same states' Phase 2 emission budgets under CSAPR. I focused on the Group 1 states because Dr. Sahu's analysis focused primarily on Group 1 states. (The Sahu analysis addresses only one Group 2 state: Texas.) As illustrated by the table below, total SO2 emissions from all Group 1 states' EGUs in 2013[1] exceeded the total of CSAPR budgets for Group 1 states by over 500,000 tons.[2]

2013 Group 1 SO2 Emissions Total	Group 1: Phase 2 Budgets Total
1,876,246	1,372,631

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[1] The present analysis uses 2012 and 2013 emissions figures, as well as state budget and assurance levels, as they appear in Tables 1, 2, 3, and 4 in the Declaration of Reid Harvey that was attached to EPA's motion to lift the stay filed on June 26, 2014.

[2] Group 1 emissions are from the U.S. Environmental Protection Agency's Clean Air Markets Division's *Air Markets Program Data* file ("CAMD Air Markets Program Data File") for the states of Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and Wisconsin.

10.   Carrying this analysis a step further, I compared EGU SO2 emissions from Group 1 states in the first quarter of 2013 to EUG SO2 emissions from those same states in the first quarter of 2014. I determined that SO2 emissions from Group 1 states increased from a total of 491,151 tons in the first quarter of 2013 to a total of 575,496 tons in the first quarter of 2014.[3] That this upward trend in SO2 emissions might continue into 2015 is supported by the year-2015 emissions forecast in the Energy Information Administration's ("EIA") *Annual Energy Outlook 2014 (AEO2014)*.[4]

11.   This information indicates that even if now-planned "scrubbers," or flue gas desulfurization devices, to reduce EGUs' SO2 emissions are installed on schedule and even if plant retirements occur when scheduled, it is likely that in 2015 there would be few SO2 allowances available for trading among states in Group 1. Moreover, any banked allowances under the Clean Air Interstate Rule ("CAIR"), which is the program that preceded CSAPR and which remains on the books unless and until the Transport Rule is implemented, cannot be carried over and used to fulfill emission reduction requirements under Phase 2 of CSAPR.   Because there will not be an abundance of allowances that EGUs in "over-budget" Group 1 states could use to meet their CSAPR Phase 2 obligations by 2015, it is not reasonable to conclude that Phase 2 of CSAPR could be implemented for Group 1 states in 2015.

12.   There are also problems with the methodology that Dr. Sahu used to compute potential emission reductions in the states he evaluated. First, Dr. Sahu selected the lowest emission rates, whether it was a single year or the average of "the three lowest" years. Sahu Dec. ¶¶ 8, 14. This approach, however, will produce biased results. To avoid such bias, it is necessary to look at operational data averaged over a longer period (typically a five- to six-year period), without using or averaging only the "lowest" years.

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[3] From CAMD Air Markets Program Data File.

[4] The electricity market regions that are included in the EIA modeling and that cover the Group 1 states are: MRO East, NPCC Upstate NY, RFC East, RFC Michigan, RFC West, SERC Gateway, SERC Central and SERC VACAR. According to the Reference Case in *AEO2014,* in 2015, SO2 emissions within these regions will total in excess of 2 million tons.

13.   Equally important, to get an accurate picture of unit emission rates, it is necessary to talk to those operating the affected units and to inquire about how a particular unit may operate in the future. For example, one can make a theoretical calculation that, at a particular facility, a newly installed scrubber with an assumed SO2 emission removal efficiency of 95 percent, with the facility using its current coal, would yield a particular emission rate. But what if the plant operator changes the coal being burned at the facility? If that happens, the emission rate might well change – it might be higher or lower. In short, if one looks at only a small window of operating data and picks the lowest emission rates within that window, and if one does not undertake a more detailed analysis that includes discussions with operators, inaccuracies in emission predictions are likely.

14.   An additional flaw is Dr. Sahu's use of the average heat input for the years 2012 and 2013 to predict future emissions. Sahu Dec. ¶8. Heat input is affected by numerous factors that change over time, such as weather, electricity demand and planned retirements of EGUs, as well as outages of EGUs – both outages that are planned and those that are unplanned due to unforeseen contingencies – during the relevant period. Thus, in cases where heat input is lower in the first year (e.g., 2012) than in the second year (2013), the use of a two-year (2012-2013) average heat input may well lead an analyst to erroneously project lower-than-actual emissions and greater-than-actual emission reductions in subsequent years. For this reason, I believe that the use of a two-year average heat input is inappropriate. To obtain a more accurate prediction, it would be better to use publicly available regional electric generation forecasts by fuel type. Such data are currently available in *AEO2014*.

State-Specific Information on SO2 Emissions

15.   The flaws in Dr. Sahu's methodology have a significant effect on his emission reduction predictions. The following is a state-by-state review of Dr. Sahu's predictions for SO2 and flaws with each. It should be noted that in this part of my analysis, I accepted, for purposes of the analysis, the following assumptions that Dr. Sahu made: (i) use of the average 2012-2013 annual heat input to estimate new or 2015 emission levels; (ii) use of Dr. Sahu's 2013 emission levels to estimate potential emission reductions; and (iii) attribution of emission reductions

to emission control technologies or EGU retirements. I made these assumptions here solely for purposes of comparison of Dr. Sahu's calculations to mine.

Texas

16.   In 2012, Texas' SO2 emission levels were 339,309 tons compared to the CSAPR Phase 2 assurance level of 347,476 tons and the state budget of 294,471 tons. In 2013, however, state SO2 emissions exceeded the state's Phase 2 assurance level: they totaled 365,657 tons, which is more than 18,000 tons above the state's Phase 2 assurance level (and more than 71,000 tons above the state's Phase 2 budget).

17.   In his declaration, Dr. Sahu concludes that Texas would be able to comply with its CSAPR Phase 2 assurance level if it were "merely" to return to 2012 SO2 emission levels. Sahu Dec. ¶19. However, electric utilities in Texas cannot reasonably be expected to cut back so significantly on the amount of generation they must produce in 2015 because there are now extremely tight reserve margins in the Electric Reliability Council of Texas ("ERCOT") and ERCOT forecasters expect about 68,000 MW of peak electric demand in 2014, which is within 1 percent of the all-time electric demand peak (68,305 MW) set on August 3, 2011.[5] Even though ERCOT expects six new combined-cycle units to begin operations in August 2014, ERCOT expects the state's existing coal resources to help meet this demand. This is confirmed by available generation data for the first quarter of 2013 and the first quarter of 2014. The data show that Texas's total generation increased from 93,657 GWh in the first quarter of 2013 to 102,041 GWh in the first quarter of 2014, while the state's coal-fired generation increased from 32,469 GW to 36,907 GWh during the same period.[6] Given these facts, it is very unlikely that Texas's SO2 emissions in 2015 will fall below the CSAPR Phase 2 budget or assurance level for Texas.

Michigan

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[5] See ERCOT news release May 1, 2014, entitled *Several new power plants expected to begin operating by late summer*, available at www.ercot.com/news/press_releases/show/26625

[6] From EIA's" Form-923 monthly data.

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18.   Dr. Sahu concludes that scrubber retrofits at DTE Energy's Monroe Units 1 and 2 should bring Michigan below that state's assurance level. Sahu Dec. ¶20. It is true that the operation of the two new scrubbers at Monroe 1 and 2 could reduce the state's SO2 emissions. The operation of the new scrubbers, however, is unlikely to yield SO2 reductions of more than 40,000 tons, as Dr. Sahu asserts. Sahu Dec. ¶20. That is because DTE is currently blending higher-emitting petroleum coke and eastern bituminous coals with the current low-sulfur sub-bituminous coal at the Monroe units with scrubbers. This type of blending will occur at the new scrubbed units at Monroe 1 and 2, based on a discussion with the plant operator.[7] This will result in potential SO2 reductions of between 32,000 to 36,000 tons. That means that after scrubber installation, Michigan's SO2 emissions will be between 14,000 and 18,000 tons above the CSAPR Phase 2 state budget (143,995 tons), requiring utilities within the state to enter an allowance market where there might well be no available allowances.

Wisconsin

19.   Dr. Sahu concludes that Wisconsin would be able to "meet its Phase 2 SO2 assurance level starting in 2015 with no difficulty" due to the operation of two new scrubbers at Columbia Units 1 and 2. Sahu Dec. ¶21. It is true that the two scrubbers at Columbia Units 1 and 2 may be able to reduce Wisconsin's 2015 SO2 emission emissions by about 20,000 tons. This misses the point, however: even with these reductions from the two Columbia units, depending on the level of 2015 emissions state-wide, Wisconsin could still be above its SO2 Phase 2 budget, thereby requiring utilities in the state to enter an allowance market in which there may well be few if any available allowances.

Pennsylvania

20.   Dr. Sahu estimates that in 2015, Pennsylvania could achieve a reduction of 185,867 tons of SO2 emissions below 2013 levels of emissions, a reduction that, he says, would put the state below its Phase 2 assurance level and Phase 2 state budget. Sahu Dec. ¶22-25 and Table 3. This calculation is incorrect.

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[7] 2013 EIA Form-923 illustrates this type of fuel blending at Monroe Units 3 and 4.

21.   The major factor contributing to Dr. Sahu's calculated 2015 emission reduction level in Pennsylvania is emission reductions projected from the Homer City Unit 1 and Unit 2 scrubbers, which – according to Dr. Sahu – will be in operation in the third quarter of 2015 and will contribute almost 106,000 tons of Pennsylvania's potential SO2 emission reductions in 2015. Sahu Dec. ¶24 & Table 3; see also Sahu Dec. ¶24 (stating, without supporting citation, that "it is my opinion that [the scrubbers] can commence operation at the end of 2014.").

22.   In fact, however, construction on the Homer City scrubbers will not be completed until the end of 2015, and full operation will not begin until 2016.[8] Therefore, there will be no potential emission reductions associated with the Homer City scrubbers in 2015.

23.   Dr. Sahu also calculates slightly over 23,000 tons of potential SO2 emission reductions from Keystone Units 1 and 2. Sahu Dec. Table 3. Dr. Sahu's calculation was premised on an assumed SO2 emission rate of 0.06 lbs/mmbtu at those units. This assumed emission rate by Dr. Sahu is incorrect. The operational SO2 emission rate for Keystone is 0.5 lbs/mmbtu, based upon a discussion with plant operator. If the correct emission rate is used, there will be no SO2 emission reductions at these units.

24.   If these two major miscalculations and other errors in Dr. Sahu's analysis are corrected, the 2015 SO2 emission reductions in Pennsylvania would be closer to 12,811 tons, as shown in Table 1 attached to this declaration. This would leave the state more than 107,000 tons above its Phase 2 assurance level of 132,185 tons.

Ohio

25.   Dr. Sahu calculates that in 2015, Ohio could potentially reduce its SO2 emissions by 143,565 tons from 2013 levels, a reduction that, he says, would bring Ohio's emissions below its Phase 2 assurance level. See Sahu Dec. ¶¶22, 26 and Table 4. I believe that this calculation is based on several faulty premises,

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[8] See Homer City Generation, L.P, *Management Financial Statements*, March 31, 2014, available at www.homercitygeneration.com/docs/Homer_City_Generation_LP_Q1_14_FS_Final.pdf.

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including the following: (i) Dr. Sahu assigned very substantial emission reductions to a coal-fired unit retiring (or converting to natural gas firing) in 2016 (Avon Lake Unit 12), and it is implausible to assume substantial emission reductions in 2015 from a unit that is planning to retire early the following year; (ii) he made errors in retirement schedules; and (iii) he miscalculated SO2 emission rates. If these errors are corrected, the data show that there would be year-2015 emission reductions in Ohio (103,241 tons below what they were in 2013, as shown in Table 2). However, that would still leave the state almost 11,000 tons above its Phase 2 assurance level of 167,843.

Indiana

26.   Dr. Sahu calculates that in 2015, Indiana sources could potentially reduce their SO2 emissions by 64,833 tons from 2013 levels. See Sahu Dec. ¶¶ 27, 28 and Table 5. Even with these reductions, however, Indiana's SO2 emissions would still exceed its Phase 2 assurance level of 196,410 tons, as Dr. Sahu concedes. In fact, the situation in Indiana is bleaker if one uses more accurate information. In particular, based on discussions with operators of the relevant facilities, I recalculated SO2 emission rates at Rockport 1 and 2 (from installation of direct sorbent injection ("DSI")), at RM Schahfer 14 and 15 (from new scrubbers),[9] and at Michigan City 12 (from a new scrubber). Using more accurate emission rate data suggests that there might be a slightly greater increase in potential reductions in 2015: 66,953 tons instead of Dr. Sahu's estimate of 64,833 tons, as shown in Table 3.

27.   Even with this recalculated net change in potential reductions, however, Indiana will still be above its state assurance level by almost 4,900 tons. Dr. Sahu suggests that to reach the state assurance level, utilities in Indiana could: (i) run existing scrubbers at higher SO2 removal efficiencies; (ii) reduce the sulfur content at several coal-fired units; and (iii) dispatch lower-emitting sources. These assertions, however, fail to take into account the following economic, regulatory, and operational issues faced by Indiana utilities.

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[9] In Dr. Sahu's tables, these units are listed as Stations 14 and 15.

- By 2015, all operating coal-fired units in Indiana will have some kind of SO2 emission control system in operation, and those without such systems will be retired by 2016. Many of these units are operating under consent decrees and either already have high SO2 removal efficiencies or demanding emission rate targets.
- Some of the units with newer scrubbers have shifted to a higher sulfur coal due to economic considerations.
- In 2012, Indiana's natural gas-fired combined-cycle facilities, which are substantially lower-emitting than coal-fired units, operated at an average 53 percent capacity factor, and for these facilities to increase their generation to displace coal-fired generation would be highly dependent on the relationship between the price of natural gas and the price of coal. If the price of natural gas remains at or above $3.50 per mmbtu (Henry Hub),[10] it is likely that there will be much displacement of coal-fired generation.

28.   Given the increase in Indiana EGUs' SO2 emissions between the first quarter of 2013 (73,467 tons) and the first quarter of 2014 (90,317 tons),[11] it is very likely that Indiana will be above its assurance level in 2015.

Kentucky

29.   Dr. Sahu calculates that by early 2015, Kentucky sources could potentially reduce their SO2 emissions by 49,284 tons from 2013 levels. Sahu Dec. ¶30 and Table 6. Even with these reductions, the state would still exceed its Phase 2 assurance level of 125,415 tons by 13,416 tons. Sahu Dec. ¶31. Errors in Dr. Sahu's 2015 reduction calculation, however, make the situation even worse for Kentucky sources. In particular, Dr. Sahu may have overestimated emission reductions attributable to Green River Units 4 and 5. These reductions account for almost 40 percent of Dr. Sahu's estimated reductions. In his analysis, Dr. Sahu assumed that these units would be retired in 2015. However, Green River's owner and operator, LGE-KU, is currently evaluating the possibility of keeping both units

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[10] According to the U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, *Energy Assurance Daily* (July 30, 2014), the Henry Hub price for July 30, 2014, was $3.75/mmbtu.

[11] From CAMD Air Market Program Data File.

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in operation through 2015 and retiring them in 2016, based on a discussion with the plant operator. This shift in the retirement schedule could reduce Dr. Sahu's estimated reductions in 2015 by over 40 percent.

30.   Other corrections to Dr. Sahu's Kentucky calculations pertain to changes in scrubber schedules and emission rates, based upon discussions with plant operators. Once these errors are corrected, there is a potential SO2 emission reduction of only 21,425 tons in 2015 from 2013 levels, as shown in Table 4. The recalculated emission reduction level pushes the state even further above its assurance level, by 41,275 tons.

31.   Dr. Sahu proposes a strategy to achieve the Phase 2 assurance level in Kentucky by reducing the capacity utilization at Paradise Units 1 and 2 and by making up the lost generation from the state's natural gas-fired capacity. The state's natural gas capacity is, however, entirely at simple-cycle combustion turbines, which are not designed to operate at levels to replace baseload coal-fired capacity such as that at the Paradise units. Taking this into account, it is clear that Kentucky will be unable to reduce its SO2 emissions to its assurance level in 2015.

Missouri

32.   Dr. Sahu uses an unusual methodological approach to estimate the seasonal and annual NOx emission reductions that could be achieved by sources in Missouri. In particular, for units that already are equipped with SCR, he selected either the average of the three lowest NOx emission rates from 2008-2012 or the 2013 NOx rate, whichever is lower. Sahu Dec. ¶14 and Tables 1 and 2 (footnote *). Using this approach, Dr. Sahu calculated that in 2015, Missouri could potentially reduce its annual NOx emissions by 30,310 tons from 2013 emissions of 75,943 tons (see Sahu Table 2). These reductions would put Missouri below both its Phase 2 annual NOx budget of 48,743 tons and its Phase 2 annual NOx assurance level of 57,517 tons.

33.   Dr. Sahu's methodological approach, however, is flawed and produces a biased result. That is because his assumed levels of emission rate performance are not achievable on a long-term basis. To determine more realistic long-term NOx emission rates, one must take into account the variability that can exist in NOx emission rates under specific regulatory regimes, which is greatly affected by

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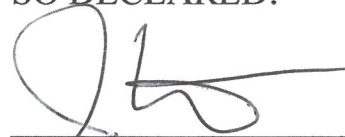
factors related to economics and plant operations, such as fuel mix, load and SCR catalyst. Rather than compute potential emission reductions based on the lowest NOx emission rate recorded, it is necessary to look at the entire 2008-2012 time period. Determining an emission rate from that data set properly takes into account the variability that may exist. A recalculated annual NOx emission reduction for Missouri – one calculated by using an entire 2008 to 2012 data set – yields a potential reduction of 15,383 tons from the state's 2013 emission level, as shown in Table 5. The recalculated level of reductions of 15,383 tons would leave the state 3,043 tons above its Phase 2 assurance level and 11,817 tons above its Phase 2 budget.

34.   Dr. Sahu uses the same biased methodology to compute potential ozone-seasonal NOx reductions in Missouri. Specifically, Dr. Sahu in his declaration calculated that in 2015, Missouri could potentially reduce its seasonal NOx emissions by 11,926 tons from the 2013 emission level of 31,482 tons (see Sahu Table 1). These reductions would put Missouri below its Phase 2 state budget (21,099 tons) and Phase 2 assurance level (25,530 tons). A recalculated seasonal NOx reduction for Missouri – based on the use of an entire 2008 to 2012 data set – yields a potential reduction of 5,101 tons from the state's 2013 emission level, as shown in Table 6. The recalculated level of reductions of 5,101 tons would leave the state 851 tons above its Phase 2 assurance level and 5,282 tons above its Phase 2 budget

Conclusion

35.   These recalculations indicate that it would be difficult, if not impossible, for states evaluated by Dr. Sahu to meet, by early 2015, their Phase 2 CSAPR budgets or, indeed, even their Phase 2 assurance levels.

SO DECLARED:

James Marchetti
DATED: July 31, 2014

Table 1 - Pennsylvania SO2

Facility Name	Unit ID	FGD Controls	2013 SO2 Emissions (tons)	2013 Heat Input (MMBtu)	2013 SO2 Rate (MMBtu)	Average of the 2012-2013 Heat Input (MMBtu)	Re-calculated SO2 Rate (lb/MMBtu)	Possible 2015 SO2 Emissions (tons)	Possible SO2 Emissions Reductions in 2015 due to SO2 Controls and Retirements (tons)	Operational Comments
Homer City	1	No	55,726	36,957,407	3.02	32,973,144	2.92	48,141	0	Construction will be completed on or about 12/31/15. Both FGDs will not be in full operation until 2016. Assume the 2008 to 2012 SO2 emission rate
Homer City	2	No	55,451	37,618,511	2.95	36,422,221	2.87	52,266	0	Construction will be completed on or about 12/31/15. Both FGDs will not be in full operation until 2016. Assume the 2008 to 2012 SO2 emission rate
Keystone	1	Yes	14,600	58,508,622	0.5	54,920,457	0.5	13,730	870	Operational SO2 emission rate 0.5, burning a 4.0lbs/mmbtu SO2 coal
Keystone	2	Yes	11,797	62,098,517	0.38	53,223,278	0.5	13,306	-1,509	Operational SO2 emission rate 0.5, burning a 4.0lbs/mmbtu SO2 coal
Bruce Mansfield	3	Yes	10,830	61,694,411	0.35	61,584,397	0.25	7,698	3,132	Consent Decree requires a 95 percent removal. Currently burning a coal with an SO2 emission rate of at least 5.0lbs/mmbtu of SO2, resulting in minimal emission rate of 0.25 lbs/mmbtu
Shawville	3	No	9,259	6,258,873	2.96	5,394,371	2.75	2,166	7,093	Retiring by April 2015. Need to prorate emission possible emission reductions. Assume retirement date April 15, 2015
Montour	2	Yes	6,440	33,116,889	0.39	35,992,568	0.41	7,378	-938	Based upon the average SO2 emission rate between 2009 to 2012. Unit is burning a 3.9 lb SO2 coal with a 89 percent removal efficiency and are expected to be operating at this level in the near term
Brunner Island	3	Yes	6,277	34,347,206	0.37	32,494,479	0.39	6,336	-59	Based upon the average SO2 emission rate between 2010 to 2012. Unit is burning a 3.9 lb SO2 coal with a 90 percent removal efficiency and are expected to be operating at this level in the near term.
Shawville	4	No	6,164	4,130,558	2.98	4,173,337	2.94	1,791	4,373	Retiring by April 2015. Need to prorate emission possible emission reductions. Assume retirement date April 15, 2015
Montour	1	Yes	5,996	34,339,654	0.35	36,193,047	0.4	7,239	-1,243	Based upon the average SO2 emission rate between 2009 to 2012. Unit is burning a 3.9 lb SO2 coal with a 90 percent removal efficiency and are expected to be operating at this level in the near term
Shawville	2	No	5,431	3,639,389	2.98	3,298,748	2.99	1,440	3,991	Retiring by April 2015. Need to prorate emission possible emission reductions. Assume retirement date April 15, 2015

Table 1 - Pennsylvania SO2

Facility Name	Unit ID	FGD Controls	2013 SO2 Emissions (tons)	2013 Heat Input (MMBtu)	2013 SO2 Rate (MMBtu)	Average of the 2012-2013 Heat Input (MMBtu)	Re-calculated SO2 Rate (lb/MMBtu)	Possible 2015 SO2 Emissions (tons)	Possible SO2 Emissions Reductions in 2015 due to SO2 Controls and Retirements (tons)	Operational Comments
Shawville	1	No	4,815	3,294,155	2.92	2,900,103	2.92	1,236	3,579	Retiring by April 2015. Need to prorate emission possible emission reductions. Assume retirement date April 15, 2015
Conemaugh	1	Yes	4,131	63,446,309	0.13	57,263,201	0.13	3,722	409	Based upon the average SO2 emission rate between 2008 to 2012. Unit is burning a 3.9 lb SO2 coal with a 97 percent removal efficiency
Bruce Mansfield	1	Yes	3,437	60,073,633	0.11	57,376,073	0.25	7,172	-3,735	Consent Decree requires a 95 percent removal. Currently burning a coal with an SO2 emission rate of at least 5.0lbs/mmbtu of SO2, resulting in minimal emission rate of 0.25 lbs/mmbtu
Brunner Island	2	Yes	3,101	15,663,810	0.4	17,059,870	0.39	3,327	-226	Based upon the average SO2 emission rate between 2010 to 2012. Unit is burning a 3.9 lb SO2 coal with a 90 percent removal efficiency and are expected to be operating at this level in the near term.
Homer City	3	Yes	3,069	33,557,512	0.18	33,608,012	0.2	3,361	-292	Based upon the average SO2 emission rate between 2008 to 2012. Unit is burning a 4.6 lb SO2 coal with a 96 percent removal efficiency
Bruce Mansfield	2	Yes	2,899	49,042,146	0.12	53,352,540	0.25	6,669	-3,770	Consent Decree requires a 95 percent removal. Currently burning a coal with an SO2 emission rate of at least 5.0lbs/mmbtu of SO2, resulting in minimal emission rate of 0.25 lbs/mmbtu
Brunner Island	1	Yes	2,798	15,916,093	0.35	12,883,779	0.39	2,512	286	Based upon the average SO2 emission rate between 2010 to 2012. Unit is burning a 3.9 lb SO2 coal with a 90 percent removal efficiency and are expected to be operating at this level in the near term.
Colver Power Project	AAB01	Yes	2,756	10,727,086	0.51	10,633,404	0.34	1,808	948	
New Castle	5	No	2,348	1,923,909	2.44	1,842,756	2.19	2,018	0	Retiring by April 2016; therefore, no emission reductions are credited in 2015
Conemaugh	2	Yes	2,278	49,514,850	0.09	51,697,953	0.13	3,360	-1,082	Based upon the average SO2 emission rate between 2008 to 2012, burning a 3.9 lb SO2 coal with a 97 percent removal efficiency
Seward	2	Yes	2,251	10,491,381	0.43	11,344,504	0.4	2,269	-18	
Ebensburg Power	31	Yes	1,935	6,107,538	0.63	6,279,561	0.4	1,256	679	
Seward	1	Yes	1,829	8,692,115	0.42	8,654,342	0.4	1,731	98	
St. Nicholas Cogen	1	Yes	1,823	10,248,638	0.36	10,748,759	0.23	1,236	587	

Pennsylvania Table (Page 2 of 3)

Table 1 - Pennsylvania SO2

Facility Name	Unit ID	FGD Controls	2013 SO2 Emissions (tons)	2013 Heat Input (MMBtu)	2013 SO2 Rate (MMBtu)	Average of the 2012-2013 Heat Input (MMBtu)	Re-calculated SO2 Rate (lb/MMBtu)	Possible 2015 SO2 Emissions (tons)	Possible SO2 Emissions Reductions in 2015 due to SO2 Controls and Retirements (tons)	Operational Comments
Cheswick	1	Yes	1,686	29,469,741	0.11	27,292,268	0.15	2,047	-361	Based upon a 98 percent removal of a 6.2 lb SO2 coal
New Castle	4	No	1,646	1,387,899	2.37	1,318,268	2.34	1,542	0	Retiring by April 2016; therefore, no emission reductions are credited in 2015
Total			230,773					206,758	12,811	

Table 2 - Ohio SO$_2$

Facility Name	Unit ID	FGD Controls	2013 SO2 Emissions (tons)	2013 Heat Input (MMBtu)	2013 SO2 Rate (MMBtu)	Average of the 2012-2013 Heat Input (MMBtu)	Re-calculated SO2 Rate (lb/MMBtu)	Possible 2015 SO2 Emissions (tons)	Possible SO2 Emissions Reductions in 2015 due to SO2 Controls and Retirements (tons)	Operational Comments
Avon Lake Power Plant	12	No	39,562	26,371,180	3	24,866,393	2.54	31,580	0	Retiring by April 2016; therefore, no emission reductions are credited in 2015
Walter C Beckjord	6	No	31,029	14,813,208	4.19	17,156,343	3.44	7,377	23,652	Retiring April 1, 2015. Assumed emission rate based upon average 2008 to 2012
Miami Fort Station	6	No	19,958	11,142,736	3.58	9,958,678	3.8	7,890	12,068	Retiring June 1, 2015. Assumed emission rate based upon average 2008 to 2012
Walter C Beckjord	5	No	19,325	8,726,639	4.43	8,704,270	3.34	3,634	15,691	Retiring April 1, 2015. Assumed emission rate based upon average 2008 to 2012
W H Zimmer Generating Station	1	Yes	18,457	89,712,238	0.41	67,597,388	0.45	15,209	3,248	Based upon the average SO2 emission rate between 2008 to 2012. Unit is burning a 6.0 lb SO2 coal with a 93 percent removal efficiency
Muskingum River	3	No	16,244	5,296,176	6.13	5,165,661	4.81	5,181	11,063	Retiring June 1, 2015. Assumed emission rate based upon average 2008 to 2012
Gen J M Gavin	1	Yes	14,719	81,308,610	0.36	85,274,811	0.31	13,218	1,501	Based upon the average SO2 emission rate between 2008 to 2012. Unit is burning a 5.7 lb SO2 coal with a 94 percent removal efficiency
Gen J M Gavin	2	Yes	13,133	68,929,336	0.38	76,562,543	0.32	12,250	883	Based on the average SO2 emission rate between 2008 to 2012. Unit is burning a 5.7 lb SO2 coal with a 94 percent removal efficiency
Muskingum River	5	No	12,919	15,564,937	1.66	11,755,074	1.59	3,897	9,022	Retiring June 1, 2015. Assumed emission rate based upon average 2008 to 2012
Killen Station	2	Yes	7,885	37,332,118	0.42	36,314,113	0.17	3,087	4,798	Planned FGD operation is 96 percent removal of 4.3 lb SO2 coal
Miami Fort Generating Station	8	Yes	6,704	34,477,867	0.39	32,960,710	0.19	3,131	3,573	Based upon the average SO2 emission rate between 2008 to 2012. Units burning a 5.8 lb SO2 coal with a 97 percent removal efficiency
Ashtabula	7	No	6,664	3,539,938	3.76	3,456,714	1.00	505	6,159	Retiring April 2015. Assumed emission rate based upon average 2008 to 2012
Miami Fort Generating Station	7	Yes	5,182	38,614,089	0.27	39,652,907	0.19	1,100	4,082	Based on the average SO2 emission rate between 2008 to 2012. Unit is burning a 5.6 lb SO2 coal with a 97 percent removal efficiency
Cardinal	1	Yes	4,636	33,440,056	0.28	30,020,546	0.375	5,629	-993	Currently burning a 7.0 lb SO2 coal at a 95 percent removal efficiency, but the design allows for a 7.5 lb coal, which Cardinal 1 & 2 may be burning in the near term
Eastlake	3	No	4,370	2,147,863	4.07	3,296,217	1.48	712	3,658	Retiring April 15, 2015. Assumed emission rate based upon average 2008 to 2012
Cardinal	2	Yes	3,993	34,452,060	0.23	36,059,023	0.375	6,761	-2,768	Currently burning a 7.0 lb SO2 coal at a 95 percent removal efficiency, but the design allows for a 7.5 lb coal, which Cardinal 1 & 2 may be burning in the near term
Eastlake	2	No	3,953	1,981,929	3.99	3,061,560	1.5	670	3,283	Retiring April 15, 2015. Assumed emission rate based upon average 2008 to 2012
Muskingum River	4	No	3,861	1,246,847	6.19	2,174,435	4.8	2,171	1,690	Retiring June 1, 2015. Assumed emission rate based upon average 2008 to 2012
J M Stuart	1	Yes	3,655	34,428,852	0.21	33,387,849	0.18	3,005	650	Consent decree calls for a station average of 96 percent. Assumed emission rate is based upon a 2012 FGD removal of 96 percent on 4.6 lb SO2 coal

Ohio Table (Page 1 of 2)

Table 2 - Ohio SO$_2$

Facility Name	Unit ID	FGD Controls	2013 SO2 Emissions (tons)	2013 Heat Input (MMBtu)	2013 SO2 Rate (MMBtu)	Average of the 2012-2013 Heat Input (MMBtu)	Re-calculated SO2 Rate (lb/MMBtu)	Possible 2015 SO2 Emissions (tons)	Possible SO2 Emissions Reductions in 2015 due to SO2 Controls and Retirements (tons)	Operational Comments
Eastlake	1	No	3,259	1,608,339	4.05	3,273,300	1.43	683	2,576	Retiring April 15, 2015. Assumed emission rate based upon average 2008 to 2012
Conesville	5	Yes	3,106	24,912,331	0.25	21,089,419	0.24	2,531	575	Emission rate is based on the unit burning a 4.5 to 5.0 lb SO2 coal at a 95 percent removal efficency on a 30 day rolling average.
J M Stuart	4	Yes	2,959	35,092,561	0.17	34,382,872	0.13	2,235	724	Consent decree calls for a station average of 96 percent. Assumed emission rate is based upon a 2012 FGD removal of 97 percent on 4.8 lb SO2 coal
Bay Shore	1	Yes	2,827	15,985,918	0.35	14,890,429	0.3	2,234	593	
J M Stuart	3	Yes	2,806	35,729,621	0.16	28,080,627	0.14	1,966	840	Consent decree calls for a station average of 96 percent. Assumed emission rate is based upon a 2012 FGD removal of 97 percent on 4.8 lb SO2 coal
Kyger Creek	2	Yes	2,293	11,774,814	0.39	12,134,482	0.75	4,550	-2,257	New FGD systems near term operation is 90 percent removal on a 7.5 lb SO2 coal
Kyger Creek	1	Yes	2,190	9,115,286	0.48	8,803,559	0.75	3,301	-1,111	New FGD systems near term operation is 90 percent removal on a 7.5 lb SO2 coal
J M Stuart	2	Yes	2,122	29,743,253	0.14	32,010,317	0.13	2,081	41	Consent decree calls for a station average of 96 percent. Assumed emission rate is based upon a 2012 FGD removal of 97 percent on 4.5 lb SO2 coal
Total			218,249					146,588	103,241	

Table 3 - Indiana SO2

Facility Name	Unit ID	FGD Controls	2013 SO2 Emissions (tons)	2013 Heat Input (MMBtu)	2013 SO2 Rate (MMBtu)	Average of the 2012-2013 Heat Input (MMBtu)	Re-calculated SO2 Rate (lb/MMBtu)	Possible 2015 SO2 Emissions (tons)	Possible SO2 Emissions Reductions in 2015 due to SO2 Controls and Retirements (tons)	Operational Comments
Rockport	MB1	No	30,839	92,775,612	0.66	94,042,378	0.47	22,100	8,739	DSI operating by April 16, 2015. DSI SO2 emission rate is 0.4 lbs/mmbtu. Assumed emission rate is the weighted average emission rate from the 2008-12 (0.64) and the DSI rate of 0.40
Rockport	MB2	No	20,797	61,477,013	0.68	76,357,380	0.47	17,944	2,853	DSI operating by April 16, 2015. DSI SO2 emission rate is 0.4 lbs/mmbtu. Assumed emission rate is the weighted average emission rate from the 2008-12 (0.64) and the DSI rate of 0.40
Wabash River Gen Station	6	No*	17,868	11,598,992	3.08	11,072,689	3.01	16,664	0	Retiring in April 2016 due to MATS extension, no emission reductions credited in 2015. There is no FGD on this unit
IPL - Petersburg Generating Station	2	Yes	14,395	17,407,868	1.65	16,438,097	0.22	1,808	12,587	Based on the average of 2008, 2011, & 2012 SO2 emission rates, because unit had a outage in 2008 that affected FGD operation. Unit is burning a 4.9 lb SO2 coal with a 96 percent removal efficiency.
IPL - Harding Street Station (EW Stout)	50	No*	13,324	6,770,399	3.94	6,406,189	3.14	10,058	0	Retiring in April 2016, no emission reductions credited in 2015. There is no FGD on this Unit 50.
IPL - Harding Street Station (EW Stout)	60	No	12,603	6,423,947	3.92	6,163,648	3.13	9,646	0	Retiring in April 2016, no emission reductions credited in 2015.
Michigan City Generating Station	12	Yes	10,429	21,341,123	0.98	22,184,882	0.85	9,429	1,000	Dry FGD operational by November 30, 2015 at a SO2 emission rate of 0.10 lbs/mmbtu
Tanners Creek	U4	No*	10,346	14,188,929	1.46	16,554,225	1.41	4,867	5,479	Retiring by June 1, 2015 and there is no FGD on Unit 4
Gibson	5	Yes*	9,887	30,507,322	0.65	31,793,623	0.71	11,287	-1,400	Based on the average SO2 emission rate between 2008 to 2012. Unit is burning a 7.3 lb SO2 coal with a 90 percent removal efficiency, indicating a FGD system on Unit 5
RM Schahfer	15	Yes	8,401	27,201,127	0.62	27,493,555	0.2	2,749	5,652	Wet FGD will become operational in the Fall of 2014 and will operating at a emission rat o 0.20 lbs/mmbtu in 2015.
IPL-Petersburg Generating Station	2	Yes*	8,129	19,955,581	0.81	21,883,297	0.19	2,079	6,050	Based on the average of 2008 to 2012 SO2 emission rates. Unit is burning a 4.8 lb SO2 coal with a 96 percent removal efficiency.
IPL - Petersburg Generating Station	3	Yes*	6,383	37,878,497	0.34	32,439,655	0.29	4,704	1,679	Based on the average of 2008 to 2012 SO2 emission rates. Unit is burning a 4.8 lb SO2 coal with a 94 percent removal efficiency.
RM Schahfer	14	Yes	6,193	18,188,583	0.68	15,521,086	0.08	621	5,572	Wet FGD went into operation in 2013, must meet a 0.08 limit (Consent Decree)
Frank E Ratts	1SG1	No*	5,376	3,695,338	2.91	3,300,934	2.81	1,544	3,832	Unit is not being retired, but will be idled in 2015 and is keeping permits. There is no FGD on Unit 1
Clifty Creek	6	Yes	5,069	9,225,668	1.1	9,672,817	0.5	2,418	2,651	New FGD systems near term operation is 90 percent removal on a 5.0 lb SO2 coal

Table 3 - Indiana SO2

Facility Name	Unit ID	FGD Controls	2013 SO2 Emissions (tons)	2013 Heat Input (MMBtu)	2013 SO2 Rate (MMBtu)	Average of the 2012-2013 Heat Input (MMBtu)	Re-calculated SO2 Rate (lb/MMBtu)	Possible 2015 SO2 Emissions (tons)	Possible SO2 Emissions Reductions in 2015 due to SO2 Controls and Retirements (tons)	Operational Comments
Clifty Creek	2	Yes	4,923	12,925,526	0.76	10,696,303	0.5	2,674	2,249	New FGD systems near term operation is 90 percent removal on a 5.0 lb SO2 coal
Frank E Ratts	2SG1	No*	4,876	3,361,459	2.9	2,880,609	2.79	1,338	3,538	Unit is not being retired, but will be idled in 2015 and is keeping permits. There is no FGD on Unit 2
IPL - Petersburg Generating Station	4	Yes	4,848	33,412,698	0.29	33,428,613	0.2	3,343	1,505	Based on the 2012 SO2 emission rate. Unit is burning a 4.9 lb SO2 coal with a 96 percent removal efficiency. FGD upgrade in 2011.
A B Brown Generating Station	1	Yes	4,457	14,006,565	0.64	13,350,937	0.64	4,272	185	Based on the average SO2 emission rate between 2008 to 2012 Unit is burning a 5.3 lb SO2 coal with a 88 percent removal efficiency.
Clifty Creek	5	Yes*	4,369	11,092,493	0.79	10,578,864	0.5	2,645	1,724	New FGD systems near term operation is 90 percent removal on a 5.0 lb SO2 coal, indicating a FGD system Unit 5
Gibson	4	Yes	3,647	35,045,890	0.21	33,803,091	0.18	3,042	605	Based on the average SO2 emission rate between 2008 to 2012. Unit is burning a 7.7 lb SO2 coal with a 98 percent removal efficiency.
Wabash River Gen Station	3	No*	3,493	2,232,175	3.13	1,968,492	3.1	3,051	0	Retiring in April 2016 due to MATS extension, no emission reductions credited in 2015. There is no FGD on this unit
IPL - Eagle Valley Generating	6	No*	3,221	3,074,127	2.1	2,388,259	2.11	2,520	0	Retiring in April 2016, no emission reductions credited in 2015. There is no FGD on this unit.
Wabash River Gen Station	4	No*	3,203	2,032,168	3.15	2,140,058	3.05	3,264	0	Retiring in April 2016 due to MATS extension, no emission reductions credited in 2015. There is no FGD on this unit
Tanners Creek	U3	No*	3,151	5,866,488	1.07	6,264,927	1.02	1,332	1,819	Retiring by June 1, 2015 and there is no FGD on Unit 3
Wabash River Gen Station	2	No*	3,022	1,902,979	3.18	2,013,724	3.1	3,121	0	Retiring in April 2016 due to MATS extension, no emission reductions credited in 2015. There is no FGD on this unit
Gibson	1	Yes*	2,782	40,748,235	0.14	39,041,311	0.11	2,147	635	Based on the average SO2 emission rate between 2008 to 2012. Unit is burning a 7.2 lb SO2 coal with a 98 percent removal efficiency.
Total			226,031					150,667	66,953	

Note: The * indicates corrections to Dr. Sahu's assumptions regarding FGD installations.

Indiana Table (Page 2 of 2)

Table 4 - Kentucky SO2

Facility Name	Unit ID	FGD Controls	2013 SO2 Emissions (tons)	2013 Heat Input (MMBtu)	2013 SO2 Rate (MMBtu)	Average of the 2012-2013 Heat Input (MMBtu)	Re-calculated SO2 Rate (lb/MMBtu)	Possible 2015 SO2 Emissions (tons)	Possible SO2 Emissions Reductions in 2015 due to SO2 Controls and Retirements (tons)	Operational Comments
Green River	5	No	12,121	6,317,700	3.84	6,291,901	3.98	12,521	0	LGE-KU looking into operation through 2015 and to retire unit in 2016. These reductions may be unlikely
Big Sandy	BSU2	No	11,711	15,878,773	1.48	17,109,336	1.4	4,994	6,717	Unit is retiring by June 1, 2015
Paradise	1	Yes	9,623	44,570,885	0.43	47,516,175	0.64	15,205	0	Received an extension on retirement through April 16, 2016 from the state, no emission reductions credited in 2015
Mill Creek	4	Yes	9,361	28,093,646	0.67	26,056,345	0.47	6,123	3,238	New FGD system to enter operation in the Fall of 2014. Assumed emission rate is the weighted average of the 2008-2012 (0.56) and targeted emission rate (0.20) for the new FGD
Paradise	2	Yes	9,202	46,169,365	0.4	45,489,306	0.7	15,921	0	Received an extension on retirement through April 16, 2016 from the state, no emission reductions credited in 2015
Mill Creek	3	Yes	8,872	22,555,009	0.79	24,833,038	0.68	8,443	429	New FGD system to enter operation in May of 2016. Assumed emission rate is the weighted average of the 2008-2012
Green River	4	No	7,877	4,188,322	3.76	3,872,658	4.03	7,803	0	LGE-KU looking into operation through 2015 and to retire unit in 2016. Therefore, these reductions may be unlikely
D B Wilson	W1	Yes	7,607	32,722,466	0.46	32,689,302	0.49	8,009	-402	Based upon the average SO2 emission rate between 2008 to 2012. Unit is burning a 5.9 lb SO2 coal with a 92 percent removal efficiency
Big Sandy	BSU1	No	7,021	9,562,887	1.47	8,546,840	1.41	6,026	0	Received a MATS extension to April 2016 and will convert to natural gas no emission reductions in 2015.
Mill Creek	2	Yes	6,534	19,162,163	0.68	17,225,196	0.34	2,928	3,606	New FGD system to enter operation in May 2015. Assumed emission rate is the weighted average of the 2008-2012 (0.53) and targeted emission rate (0.20) for the new FGD
Ghent	2	Yes	6,323	36,426,543	0.35	33,145,980	0.27	4,475	1,848	Based on the average SO2 emission rate between 2010 to 2012. Unit is burning a 5.3 lb SO2 coal with a 95 percent removal efficiency

Table 4 - Kentucky SO2

Facility Name	Unit ID	FGD Controls	2013 SO2 Emissions (tons)	2013 Heat Input (MMBtu)	2013 SO2 Rate (MMBtu)	Average of the 2012-2013 Heat Input (MMBtu)	Re-calculated SO2 Rate (lb/MMBtu)	Possible 2015 SO2 Emissions (tons)	Possible SO2 Emissions Reductions in 2015 due to SO2 Controls and Retirements (tons)	Operational Comments
Elmer Smith	2	Yes	5,414	20,350,020	0.53	18,482,977	0.5	4,621	793	Based on the average SO2 emission rate between 2080 to 2012. Unit is burning a 6.5 lb SO2 coal with a 93 percent removal efficiency
Ghent	3	Yes	4,967	34,725,149	0.29	33,817,921	0.23	3,889	1,078	Based on the average SO2 emission rate between 2008 to 2012. Unit is burning a 5.2 lb SO2 coal with a 96 percent removal efficiency
Mill Creek	1	Yes	4,680	14,609,365	0.64	16,952,982	0.3	2,543	2,137	New FGD system to enter operation in April 2015. Assumed emission rate is the weighted average of the 2008-2012 (0.49) and targeted emission rate (0.20) for the new FGD
Coleman	C3	Yes	3,863	12,591,557	0.61	12,599,878	0.26	1,638	2,225	Based on the average SO2 emission rate between 2008 to 2012. Unit is burning a 4.8 lb SO2 coal with a 95 percent removal efficiency
Shawnee	5	No	3,249	9,020,451	0.72	9,108,901	0.71	3,234	0	Based on the average SO2 emission rate between 2008 to 2012.
Shawnee	8	No	3,189	8,974,833	0.71	8,891,739	0.70	3,112	0	Based on the average SO2 emission rate between 2008 to 2012.
Shawnee	4	No	3,158	8,736,818	0.72	8,229,272	0.73	3,004	0	Based on the average SO2 emission rate between 2008 to 2012.
Shawnee	1	No	3,095	8,599,786	0.72	7,508,877	0.71	2,666	0	Based on the average SO2 emission rate between 2008 to 2012.
Shawnee	3	No	3,056	8,483,257	0.72	8,126,894	0.71	2,885	0	Based on the average SO2 emission rate between 2008 to 2012.
Shawnee	6	No	3,000	8,480,477	0.71	8,497,741	0.70	2,974	0	Based on the average SO2 emission rate between 2008 to 2012.
Shawnee	7	No	2,884	8,021,275	0.72	8,744,419	0.71	3,104	0	Based on the average SO2 emission rate between 2008 to 2012.
Shawnee	9	No	2,847	8,038,678	0.71	8,500,597	0.70	2,975	0	Based on the average SO2 emission rate between 2008 to 2012.
John S. Cooper	1	No	2,812	4,106,883	1.37	4,879,573	2.00	4,880	0	Dry FGD to be connected to Unit 2 in 2016
Shawnee	2	No	2,731	7,557,731	0.72	8,137,156	0.73	2,970	0	Based on the average SO2 emission rate between 2008 to 2012.

Table 4 - Kentucky SO2

Facility Name	Unit ID	FGD Controls	2013 SO2 Emissions (tons)	2013 Heat Input (MMBtu)	2013 SO2 Rate (MMBtu)	Average of the 2012-2013 Heat Input (MMBtu)	Re-calculated SO2 Rate (lb/MMBtu)	Possible 2015 SO2 Emissions (tons)	Possible SO2 Emissions Reductions in 2015 due to SO2 Controls and Retirements (tons)	Operational Comments
R D Green	G1	Yes	2,702	18,521,436	0.29	18,133,522	0.17	1,541	1,161	Based on the average SO2 emission rate between 2008 to 2012. Unit is burning a 5.8 lb SO2 coal with a 97 percent removal efficiency
Paradise	3	Yes	2,698	38,271,742	0.14	51,273,530	0.16	4,102	-1,404	Based on the average SO2 emission rate between 2009 to 2012. Unit is burning a 4.8 lb SO2 coal with a 97 percent removal efficiency
Total			150,597					142,586	21,425	

Table 5 - Missouri (Annual NOx)

Facility Name	Unit	SCR	2013 NOx Emissions (tons)	2013 Heat Input (MMBtu)	2013 NOx Rate (lb/ MMBtu)	Avg. 2012-2013 Heat Input	Avg. of 3 lowest Annual NOx rates (lb/ (lb/ MMBtu) MMBtu)	Re-calculated NOx rate	Possible 2015 NOx Emissions (tons)	Possible NOx Emissions Reductions in 2015 due to NOx Controls and Retirements (tons)	Operational Comments
New Madrid Power Plant	2	Yes	12,071	38,581,042	0.63	38,247,530	0.17	0.27	5,163	6,908	Based on the average emission rate between 2009 and 2013
New Madrid Power Plant	1	Yes	10,256	38,683,085	0.53	37,504,657	0.12	0.35	6,563	3,693	Based on the average emission rate between 2009 and 2013
Thomas Hill Energy Center	MB2	Yes	7,271	21,282,561	0.68	19,064,219	0.33	0.46	4,385	2,886	Based on the average emission rate between 2009 and 2013
Thomas Hill Energy Center	MB1	Yes	4,562	14,889,551	0.61	14,330,448	0.12	0.29	2,078	2,484	Based on the average emission rate between 2009 and 2013
Thomas Hill Energy Center	MB3	Yes	3,994	48,341,695	0.17	46,174,768	0.1	0.16	3,694	300	Based on the average emission rate between 2009 and 2013
Sioux	1	No	3,080	25,045,245	0.25	23,909,957	0.26	0.27	3,228	-148	Based on the average emission rate between 2009 and 2013
Sioux	2	No	2,924	24,262,185	0.24	24,337,736	0.24	0.25	3,042	-118	Based on the average emission rate between 2009 and 2013
Asbury	1	Yes	2,290	15,933,028	0.29	14,865,750	0.14	0.18	1,338	952	Based on the average emission rate between 2009 and 2013
Labadie	1	No	1,921	41,394,242	0.09	42,287,846	0.1	0.1	2,114	-193	Based on the average emission rate between 2009 and 2013
Labadie	2	No	1,904	38,948,252	0.1	35,846,610	0.11	0.11	1,972	-68	Based on the average emission rate between 2009 and 2013
Labadie	4	No	1,831	41,543,426	0.09	38,830,433	0.1	0.1	1,942	-111	Based on the average emission rate between 2009 and 2013
Labadie	3	No	1,819	37,973,504	0.1	36,926,971	0.11	0.11	2,031	-212	Based on the average emission rate between 2009 and 2013
Sibley	3	Yes	1,809	20,730,850	0.17	20,107,060	0.12	0.14	1,407	402	Based on the average emission rate between 2009 and 2013
Lake Road	6	No	1,723	5,284,913	0.65	4,702,472	0.66	0.67	1,575	148	Based on the average emission rate between 2009 and 2013
Iatan	1	Yes	1,554	46,876,303	0.07	50,523,350	0.07	0.08	2,021	-467	Based on the average emission rate between 2009 and 2013
Rush Island	2	No	1,542	37,860,229	0.08	36,438,901	0.08	0.09	1,640	-98	Based on the average emission rate between 2009 and 2013
Rush Island	1	No	1,525	36,480,883	0.08	37,118,252	0.08	0.09	1,670	-145	Based on the average emission rate between 2009 and 2013
Iatan	2	Yes	1,448	56,358,120	0.05	59,306,736	0.05	0.05	1,483	-35	Based on the average emission rate between 2010 and 2013

Table 5 - Missouri (Annual NOx)

Facility Name	Unit	SCR	2013 NOx Emissions (tons)	2013 Heat Input (MMBtu)	2013 NOx Rate (lb/ MMBtu)	Avg. 2012-2013 Heat Input	Avg. of 3 lowest Annual NOx rates (lb/ (lb/ MMBtu) MMBtu)	Re-calculated NOx rate	Possible 2015 NOx Emissions (tons)	Possible NOx Emissions Reductions in 2015 due to NOx Controls and Retirements (tons)	Operational Comments
New Madrid Power Plant	2	Yes	12,071	38,581,042	0.63	38,247,530	0.17	0.27	5,163	6,908	Based on the average emission rate between 2009 and 2013
New Madrid Power Plant	1	Yes	10,256	38,683,085	0.53	37,504,657	0.12	0.35	6,563	3,693	Based on the average emission rate between 2009 and 2013
Thomas Hill Energy Center	MB2	Yes	7,271	21,282,561	0.68	19,064,219	0.33	0.46	4,385	2,886	Based on the average emission rate between 2009 and 2013
Thomas Hill Energy Center	MB1	Yes	4,562	14,889,551	0.61	14,330,448	0.12	0.29	2,078	2,484	Based on the average emission rate between 2009 and 2013
Thomas Hill Energy Center	MB3	Yes	3,994	48,341,695	0.17	46,174,768	0.1	0.16	3,694	300	Based on the average emission rate between 2009 and 2013
Sioux	1	No	3,080	25,045,245	0.25	23,909,957	0.26	0.27	3,228	-148	Based on the average emission rate between 2009 and 2013
Sioux	2	No	2,924	24,262,185	0.24	24,337,736	0.24	0.25	3,042	-118	Based on the average emission rate between 2009 and 2013
Asbury	1	Yes	2,290	15,933,028	0.29	14,865,750	0.14	0.18	1,338	952	Based on the average emission rate between 2009 and 2013
Labadie	1	No	1,921	41,394,242	0.09	42,287,846	0.1	0.1	2,114	-193	Based on the average emission rate between 2009 and 2013
Chamois Power Plant	2	No	1,442	3,067,657	0.94	3,158,608	0.87	-	0	0	Closed in September 2013, need to account for replacement generation
Hawthorn	5A	Yes	1,378	37,625,680	0.07	37,678,417	0.07	0.07	1,319	59	Based on the average emission rate between 2010 and 2013
Montrose	1	No	1,281	7,833,294	0.33	7,746,636	0.33	0.33	1,278	3	Based on the average emission rate between 2009 and 2013
Sikeston	1	No	1,264	19,103,660	0.13	18,013,947	0.21	0.22	1,982	-718	Based on the average emission rate between 2008 and 2012
Meramec	4	No	948	11,401,953	0.17	14,778,945	0.18	0.18	1,330	-382	Based upon the average emission rate between 2009 and 2013
Montrose	2	No	919	11,780,332	0.16	9,218,975	0.29	0.16	738	181	Based on 2013 emission rate, LNB/OFA was installed in 2012
Montrose	3	No	882	11,317,127	0.16	8,876,660	0.29	0.16	710	172	Based on 2013 emission rate, LNB/OFA was installed in 2012
James River	5	No	596	4,973,917	0.24	4,654,945	0.19	0.21	489	107	Based on the average emission rate between 2009 and 2013
Meramec	3	No	541	6,440,098	0.17	8,928,697	0.17	0.17	759	-218	Based on the average emission rate between 2009 and 2013
Total			72,775						55,950	15,383	

Table 6 Missouri (Ozone-season NOx)

Facility Name	Unit	SCR	2013 NOx Emissions (tons)	2013 Heat Input (MMBtu)	2013 NOx Rate (lb/ MMBtu)	Avg. 2012-2013 Heat Input	Avg. of 3 lowest OS NOx rates (lb/ (lb/ MMBtu) MMBtu)	Re-calculated NOx rate	Possible 2015 NOx Emissions (tons)	Possible NOx Emissions Reductions in 2015 due to NOx Controls and Retirements (tons)	Operational Comments
New Madrid Power Plant	2	Yes	4,328	17,278,766	0.5	16,769,657	0.09	0.26	2,180	2,148	Based on the average emission rate between 2009 and 2013
New Madrid Power Plant	1	Yes	4,126	13,447,549	0.61	15,742,672	0.09	0.33	2,598	1,528	Based on the average emission rate between 2009 and 2013
Thomas Hill Energy Center	MB2	Yes	2,430	7,926,738	0.61	8,660,415	0.33	0.46	1,992	438	Based on the average emission rate between 2009 and 2013
Thomas Hill Energy Center	MB1	Yes	1,812	6,168,477	0.59	6,587,779	0.09	0.28	922	890	Based on the average emission rate between 2009 and 2013
Thomas Hill Energy Center	MB3	Yes	1,786	23,130,695	0.15	20,823,789	0.08	0.11	1,145	641	Based on the average emission rate between 2009 and 2013
Sioux	1	No	1,523	12,465,155	0.24	11,787,204	0.23	0.26	1,532	-9	Based on the average emission rate between 2009 and 2013
Sioux	2	No	1,269	10,693,714	0.24	9,963,958	0.23	0.24	1,196	73	Based on the average emission rate between 2009 and 2013
Asbury	1	Yes	960	7,039,789	0.27	6,020,405	0.14	0.18	542	418	Based on the average emission rate between 2009 and 2013
Labadie	2	No	864	18,145,210	0.1	15,526,209	0.1	0.1	776	88	Based on the average emission rate between 2009 and 2013
Chamois Power Plant	2	No	777	1,664,391	0.93	1,550,365	0.85	-	0	0	Closed in September 2013, need to account for replacement generation
Labadie	3	No	774	16,466,559	0.09	16,974,096	0.11	0.11	934	-160	Based on the average emission rate between 2009 and 2013
Labadie	1	No	768	17,032,904	0.09	16,972,444	0.1	0.1	849	-81	Based on the average emission rate between 2009 and 2013
Labadie	4	No	763	17,099,567	0.09	18,445,063	0.1	0.1	922	-159	Based on the average emission rate between 2009 and 2013
Lake Road	6	No	728	2,134,276	0.68	2,251,031	0.64	0.66	743	-15	Based on the average emission rate between 2009 and 2013
Iatan	2	Yes	718	27,389,868	0.05	26,124,538	0.05	0.05	653	65	Based on the average emission rate between 2011 and 2013
Sibley	3	Yes	715	8,780,392	0.16	8,616,507	0.1	0.13	560	155	Based on the average emission rate between 2009 and 2013
Rush Island	1	No	651	15,373,057	0.08	16,274,205	0.09	0.09	732	-81	Based on the average emission rate between 2009 and 2013
Montrose	1	No	646	3,940,867	0.33	4,423,104	0.33	0.32	708	-62	Based on the average emission rate between 2009 and 2013
Rush Island	2	No	645	15,871,549	0.08	14,747,902	0.08	0.09	664	-19	Based on the average emission rate between 2009 and 2013
Meramec	4	No	585	6,990,800	0.17	7,614,565	0.18	0.18	685	-100	Based on the average emission rate between 2009 and 2013

Table 6 - Missouri (Ozone-season NOx)

Facility Name	Unit	SCR	2013 NOx Emissions (tons)	2013 Heat Input (MMBtu)	2013 NOx Rate (lb/ MMBtu)	Avg. 2012-2013 Heat Input	Avg. of 3 lowest OS NOx rates (lb/ (lb/ MMBtu) MMBtu)	Re-calculated NOx rate	Possible 2015 NOx Emissions (tons)	Possible NOx Emissions Reductions in 2015 due to NOx Controls and Retirements (tons)	Operational Comments
Iatan	1	Yes	576	18,363,316	0.06	21,194,112	0.07	0.08	848	-272	Based on the average emission rate between 2009 and 2013
Hawthorn	5A	Yes	546	14,790,981	0.07	16,467,623	0.07	0.07	576	-30	Based on the average emission rate between 2009 and 2013
Sikeston	1	No	463	8,900,968	0.1	8,453,941	0.21	0.19	803	-340	Based on the average emission rate between 2008 and 2012
Meramec	3	No	462	5,535,373	0.17	6,132,711	0.17	0.17	521	-59	Based on the average emission rate between 2009 and 2013
Montrose	2	No	384	4,822,372	0.16	4,248,402	0.26	0.16	340	44	Based on 2013 emission rate, LNB/OFA was installed in 2012
TOTAL			29,299						23,421	5,101	

Missouri Ozone-season NOx Table (Page 2 of 2)