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VIA FEDERAL EXPRESS

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ENTERGY CORPORATION'S INITIAL PETITION FOR RECONSIDERATION AND REQUEST FOR STAY OF THE CROSS-STATE AIR POLLUTION RULE

Docket No. EPA-HQ-OAR-2009-0491

I. INTRODUCTION

Entergy Corporation ("Entergy"), by and through Entergy Services, Inc., its general services subsidiary, respectfully submits this petition for reconsideration and request for stay of the Cross-State Air Pollution Rule ("CSAPR"). 76 Fed. Reg. 48,208 (Aug. 8, 2011). Entergy notes that EPA has proposed changes to the CSAPR as of October 6. Entergy has not had time to analyze fully the proposed changes but will address the proposal in comments. Entergy also notes that the impact of EPA's October 6 announcement on the finality and effect of the CSAPR as published in August is unclear, as is the impact on deadlines imposed by the Administrative Procedures Act and the Federal Rules of Appellate Procedures for petition filings. At this time, Entergy requests that EPA reconsider its decision to include the States of Louisiana, Mississippi and Arkansas in the ozone season NOx control program under CSAPR. If EPA retains Louisiana, Mississippi and Arkansas in the rule, EPA must revise its unsupportable state budgets for these three states and postpone the 2012 compliance deadline. Entergy further requests that EPA immediately stay the final rule for Louisiana, Mississippi and Arkansas.

While this petition for reconsideration is focused on Louisiana, Mississippi and Arkansas, Entergy also requests that EPA reconsider the late addition of Texas to the annual NOx and SO_2 programs, the Texas seasonal NOx budget, and the unreasonable 2012 compliance deadline, and requests that EPA also stay the rule with respect to Texas. Entergy adopts the arguments relating to Texas already filed by other petitioners, including the State of Texas, Luminant Generation Company, Northern States Power Company - Minnesota, and Southwestern Public Service Company.[1]

As set forth more fully below, EPA provided inadequate opportunity for comment on the state budgets for the CSAPR and the substantive bases EPA relied on in setting the state budgets. The Louisiana, Mississippi and Arkansas state budgets were cut substantially between the proposal and the final rule without any opportunity for comment. Entergy therefore did not have the ability to provide EPA information on the errors inherent in those budgets. Second, EPA's reliance on the Integrated Planning Model ("IPM") is unreasonable given the important and fundamental limitations in the IPM, which have produced gross errors in projecting electric generator dispatch and utilization, resulting in a significant underestimate of base case emissions. The IPM-predicted base case emissions for 2012 in these states are not representative of actual emissions in these states, and the limitations of the model, including the failure to take into account the transmission constraints and generation/load pockets with which electric utilities must contend, render the model an inappropriate isolated tool for developing state allowance budgets. EPA's use of IPM's base case projections results in an assumption that the "base case" budgets will not require any sources in these three states to reduce emissions beyond business-as-usual. This assumption is manifestly wrong, and the reductions required in a few short months are draconian. Finally, EPA should remove Louisiana, Mississippi and Arkansas from the CSAPR because, by EPA's own analysis, these states cannot achieve cost-effective emission reductions below EPA's projected "base case" generation level. EPA admits that generators in these states cannot avoid emissions increases within the states at costs below EPA's applicable threshold. As a result, these states do not meet EPA's definition of significant contribution and should not be included within the rule.

Again, Entergy takes note of the EPA October 6 announcement and continues to review this announcement and its impact. The October 6 announcement, however, is the announcement of a proposed EPA action which may or may not be implemented after the announced notice and

[1] The petitions for reconsideration filed by Texas, Luminant Generation Company, Northern States Power Company - Minnesota, and Southwestern Public Service Company are attached as Exhibits A, B, C, and D, respectively.

comment period. For the purpose of the October 7, 2011 deadline for filing this petition, therefore, Entergy must consider the August 2011 final CSAPR as the currently operative rule.

II. BACKGROUND

Entergy Corporation operates an integrated electric utility system in four states -- Arkansas, Louisiana, Mississippi and Texas -- serving 2.7 million customers. Entergy owns and operates power plants with approximately 30,000 MW of electric generating capacity. Entergy also is the second largest nuclear generating company in the United States. Each of Entergy's fossil-fuel fired electric generating units over 25 MW are covered by CSAPR under the seasonal NOx program. Entergy also owns and operates a transmission system managed under an Independent Coordinator of Transmission ("ICT") arrangement in which the Southwest Power Pool ("SPP") currently serves as the ICT (for clarification, Entergy's transmission system does not operate as part of the SPP regional transmission organization). Entergy is responsible for complying with mandatory electric reliability standards promulgated by the North American Electric Reliability Corporation ("NERC") and approved by the Federal Energy Regulatory Commission ("FERC"). *See* 18 C.F.R. §§ 39.2(b), 39.5, 39.7 (2010). Failure to comply with these standards can affect the ability of the power grid to operate reliably as well subject Entergy to financial penalties. *See* 18 C.F.R. § 39.7; *see also Mandatory Reliability Standards for the Bulk-Power System*, FERC Stats. & Regs. ¶ 31,242 at P 21-22, 221 (2007) (Order No. 693), *reh'g denied*, 120 FERC ¶ 61,053 (2007). Certain standards require that Entergy plan and operate its transmission system within specified limits and be able to return the system to normal operation within specified time periods and after the loss of a single element of the system. *See* FERC Order No. 693, at PP 1590, 1599, 1627, 1635, 1757, 1764, 1771, 1784 (approving Reliability Standards TPL-001, TPL-002, TOP-002, TOP-004).

CSAPR was published in the Federal Register on August 8, 2011. 76 Fed. Reg. 48,208. CSAPR was developed in response to the U.S. Circuit Court for the District of Columbia Circuit's remand of the Clean Air Interstate Rule ("CAIR") in 2008. *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008), modified on rehearing, *North Carolina v. EPA*, 550 F.3d 1176, 1178 (D.C. Cir. 2008). In response, EPA proposed the Clean Air Transport Rule ("CATR") in July 2010. 75 Fed. Reg. 45,210 (July 6, 2010). CATR, similar to CAIR and CSAPR, relied on the IPM to predict utilization of electric generating units ("EGUs") for setting state budgets and unit allocations. Entergy commented on CATR and generally supported the proposed state budgets for Louisiana, Arkansas, Mississippi and Texas, with some qualifications. Entergy objected to the unit allowance allocation methodology, however, because CATR failed to provide any allowances to a significant number of Entergy's units that must operate for system reliability, but which the IPM model predicted would not run at all. *See* Entergy Services, Inc. CATR comment letter, Dkt. No. EPA-HQ-OAR-2009-0491-2847 (Oct. 1, 2010) (Attached as Exhibit E).

EPA promulgated the final CSAPR on August 8, 2011. CSAPR varied from CATR in several critical respects as it applies to many states, including Louisiana, Mississippi and Arkansas. First, the state ozone season NOx budgets for Louisiana, Mississippi and Arkansas were reduced by 37%, 39% and 10%, respectively. Second, CSAPR concluded that Louisiana, Mississippi, and Arkansas could not achieve NOx emission reductions below the "base case" at costs that met EPA's "highly cost-effective" threshold of $500 per ton. EPA nonetheless, included all three states and set state budgets at the projected 2012 base case level to preclude "leakage." This leakage justification was presented for the first time at the final rule stage. EPA provided no analysis of the cost per ton of avoided emissions within the states to address this potential leakage.

Under CSAPR, using the IPM to predict EGU utilization in Louisiana, Mississippi and Arkansas, EPA set state budgets and the allocations (based on historic heat input) to individual facilities in those states for 2012 and beyond. Under this "2012 base case" scenario, Entergy's covered sources in Louisiana will be allocated seasonal NOx allowances that are approximately **51%** below actual 2010 emissions. In Mississippi, Entergy's covered sources will be allocated seasonal NOx allowances that are **47%** below 2010 actual emission levels. In Arkansas, Entergy's covered sources will be allocated seasonal NOx allowances that are **18%** below 2010 actual emission levels. This is the case despite the fact that this is IPM's prediction of what will be the case without CAIR or CSAPR. For Entergy's system, as a whole, the aggregate unit allocations under CSAPR to Entergy's covered units is 47% lower than Entergy's average annual NOx emissions for the past three years. CSAPR does not explain this huge discrepancy between the IPM projection and reality, but the fact that it projects zero utilization for a large number of units that must be operated under system reliability requirements explains part of the problem.

CSAPR imposes these large emission reductions on Entergy's system in a time frame that precludes installation of large emission control capital projects. The result is that Entergy will be faced with the prospect of non-compliance with CSAPR requirements, expenditure of many millions of dollars to acquire allowances, if they are available, or jeopardizing electric reliability with all of the attendant impacts, including health, safety and economic consequences.

III. REQUESTS FOR RECONSIDERATION AND REQUESTS FOR STAY

For the reasons set forth below, Entergy urges EPA to withdraw CSAPR and provide an opportunity for comment on the IPM projections, the state budgets and unit allocations. The change in state budgets in Louisiana, Mississippi and Arkansas from the proposed rule to the final rule is so dramatic, and the underpinning rationale for the budget so flawed, that EPA must give states and stakeholders an opportunity to analyze and comment on the changes. Entergy also urges EPA to reconsider the inclusion of Louisiana, Mississippi and Arkansas, as well as the unreasonable 2012 compliance deadline. Based on EPA's own analysis, these three states cannot achieve cost effective emission reductions and, as a result, should not have been included in the Rule.

A. EPA Reconsideration and Stay Is Authorized Under Section 307(d)(7)(B).

Section 307(d)(7)(B) of the federal Clean Air Act ("CAA") provides for EPA's reconsideration of a CAA rule upon objection by a petitioner. *See* 42 U.S.C. § 7607(d)(7)(B). EPA *must* grant reconsideration when the petitioner:

> [c]an demonstrate to the Administrator that it was impracticable to raise [an] objection [during the period for public comment] or if the grounds for such objection arose after the period for public

> comment ... and if such objection is of central relevance to the outcome of the rule.

Id. In such a situation, reconsideration is mandatory, as the CAA commands that EPA "*shall* convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed." *Id.* (emphasis added). The reconsideration provision of Section 307(d)(7)(B) is applicable to the CSAPR rulemaking because the Administrator expressly determined that CSAPR is subject to the procedural provisions of CAA § 307(d). *See* 76 Fed. Reg. at 48,352.

The CAA authorizes EPA to stay the effectiveness of the rule for up to three months during reconsideration. *See* 42 U.S.C. § 7607(d)(7)(B). The Administrative Procedure Act ("APA") further authorizes EPA to stay the effectiveness of a rule indefinitely during reconsideration. Under the APA, "[w]hen an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review." 5 U.S.C. § 705. EPA has applied this standard to CAA actions. *See, e.g.,* Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Aggregation, 75 Fed. Reg. 27,643 (May 18, 2010). The standard for such an administrative stay is different from the standard for a stay used by the courts because a judicial stay requires a demonstration of irreparable harm. This is clear from the text of the APA:

> When an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review. On such conditions as may be required and to the extent necessary to prevent irreparable injury, the reviewing court ... may issue all necessary and appropriate process to postpone the effective date of an agency action or to preserve status or rights pending conclusion of the review proceedings.

5 U.S.C. § 705.

Thus, the APA deliberately contrasts what is required for an administrative stay—"justice so requires" — and a judicial stay — "conditions as may be required" and "irreparable harm." Similarly, CAA Section 307(d)(7)(B) authorizes an administrative stay, but does not premise that stay on a finding of irreparable injury. Such differences must be given effect,[2] so there is no irreparable harm requirement for an administrative stay. Given the potential impact of these regulations on Entergy's system reliability and the risk that poses to its customers and the state economies, "justice so requires" that EPA stay the new provisions of the final rule and take other necessary and appropriate steps to defer the compliance deadlines and other provisions of the final rule until the outcome of the reconsideration process.

[2] "[W]here Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion." *Russello v. United States,* 464 U.S. 16, 23 (1983) (quotation marks and citation omitted; alteration in original).

B. EPA's Dramatic Reduction In The Louisiana, Mississippi and Arkansas State Budgets And The Significant Changes In The IPM Projections Required Notice and Comment.

The final state emission budgets for Louisiana, Mississippi and Arkansas cannot be viewed as a logical outgrowth of CATR. Between the publication of CATR and EPA's final promulgation of CSAPR, EPA revised the IPM, a proprietary model that is not accessible to the general public, to reduce drastically the emissions budgets for Louisiana, Mississippi, and Arkansas. In Louisiana, EPA cut the state budget by 37%; in Mississippi by 39%; and in Arkansas by 10%. Neither CATR nor the notices of data availability that EPA issued provided the states or affected companies with any notice that the state budgets would be slashed in the final rule.

The CAA and APA impose stringent notice and comment requirements on EPA. "Given the strictures of notice-and-comment rulemaking, an agency's proposed rule and its final rule may differ only insofar as the latter is a 'logical outgrowth' of the former." *Envtl. Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005) (stating that "[t]he test is whether a new round of notice and comment would provide the first opportunity for interested parties to offer comments that could persuade the agency to modify its rule"). A "final rule is a 'logical outgrowth' of a proposed rule only if interested parties should have anticipated that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *Id.* at 998.

During the comment period for CATR, Entergy did not object to the overall level of the Louisiana, Mississippi, and Arkansas state emissions budgets because Entergy believed that compliance with the proposed state budgets would be achievable. Instead, Entergy focused its comments on the unit-level allocation methodology. In CATR, the allowance allocation methodology would have allocated allowances to units based on the IPM's prediction of utilization and emissions. For Entergy, the IPM predicted that approximately 23 of its units would not be utilized and, as a result, would have received no allowances, while another 10 units were predicted to be underutilized. Entergy noted that these units would, in fact, have to run and that Entergy supported an alternative methodology that allocated allowances based on an output-based method or, alternatively, on a historic heat input basis. *See, e.g.,* Entergy Services, Inc., CATR comment letter, Dkt. No. EPA-HQ-OAR-2009-0491-2847 (Oct. 1, 2010) (Exhibit E). ("IPM possesses several characteristics that may contribute to its under-prediction of unit operations and premature retirement or significant reduction of generation from oil/gas steam units. This is demonstrated in the data contained in Attachment A. A review of this data reveals IPM modeling marks the early retirement 23 Entergy oil/gas steam units that were utilized significantly in 2007-2010 to supply power to the grid and underutilizes 10 Entergy combustion turbine units that were utilized significantly in 2007-2010 to supply power to the grid. Entergy does not have any plans to retire the units predicted to retire, nor do we expect utilization of these units or the turbines to change significantly.")

Entergy also commented on EPA's January 7, 2011 notice of data availability ("NODA"), 76 Fed. Reg. 1109 (Jan. 7, 2011), and supported the Option 1 methodology based on historic heat input. *See* Entergy Services, Inc., NODA comment letter, Dkt. No. EPA-HQ-OAR-

2009-0491-3986 (Feb. 7, 2010) (Attached as Exhibit F). EPA requested comment on, among other things, "[t]he underlying unit-level data and resulting allocations for the alternative allocation methodologies based on the proposal's state budget." *Id.* at 1112. EPA sought comment on the unit-level allocations "to ensure that we use the best available data in the Transport Rule FIP allocation process." *Id.* at 1116. With a revised unit-level allocation methodology *and the proposed state emissions budgets*, Entergy estimated that compliance with the proposed transport rule would be possible. Again, there was nothing in the NODA to signal to Entergy that the Louisiana, Mississippi and Arkansas budgets would be reduced by 39%, 37% and 10%.

EPA's failure to provide notice that the proposed state emissions budgets for Louisiana, Mississippi, and Arkansas would be reduced drastically in the final rule is impermissible. *Horsehead Resource Dev. Co. v. Browner*, 16 F.3d 1246, 1268 (D.C. Cir. 1994) (finding that an agency's notice of proposed rulemaking must provide sufficient detail for interested parties to comment meaningfully). EPA reduced the final state emissions budgets for Louisiana, Mississippi and Arkansas by significant amounts -- 39%, 37%, and 10%, respectively. As the OMB Interagency Working Group recognized, "the sheer magnitude of change to the budgets of all of the states results in a significantly different rule than originally proposed." OMB Summary of Interagency Working Comments on Draft Language, § E (July 11, 2011) (Attached as Exhibit G). Because CSAPR is a trading program, state emissions budgets play a key role in compliance planning. *See* 76 Fed. Reg. 48,272 ("EPA believes that the preferred trading remedy will allow source owners to choose among several compliance options to achieve required emission reductions in the most cost effective manner, such as installing controls, changing fuels, reducing utilization, buying allowances, or any combination of these actions.") Without knowing, at least approximately, the state budgets, variability limits and unit-level allocations, Entergy simply had no opportunity to begin planning for compliance with CSAPR in any meaningful way. "Interested parties cannot be expected to divine the EPA's unspoken thoughts." *Shell Oil Co. v. EPA*, 950 F.2d 741, 751 (D.C. Cir. 1991).

EPA's decision not to seek comment on the state emissions budgets established by CSAPR denied Entergy the opportunity to examine why the budgets were so low and explain to EPA in comments that the IPM (or EPA's use and application of the IPM) is seriously flawed and that the Agency's underlying assumptions or the data inputs to the IPM are inaccurate. Entergy has worked diligently with EPA since CSAPR has become final to provide EPA with extensive information regarding the errors in the IMP's use and its limitations. Entergy urges EPA to stay the rule and seek comment on the CSAPR and allow companies and states to address the flaws in the IPM's application here, the state budgets and the assumptions underlying both.

C. The Louisiana and Mississippi Emissions Budgets Are Arbitrary And Capricious.

The IPM model, on which the entire CSAPR depends, predicts that 2012 NOx emissions in Louisiana, Mississippi and Arkansas will be significantly lower than actual 2010 ozone season emission levels. This is EPA's "base case." That is, the IPM model makes this prediction on the basis of CAIR being rescinded, so there are no NOx allowances costs associated with the IPM predictions or other SIP-related environmental constraints imposed on the generation.[3] Actual 2010 emissions are dramatically higher, notwithstanding that the system currently is being dispatched based on marginal variable costs, which *includes* the current CAIR NOx costs. Inclusion of NOx costs should lead to lower, rather than higher, aggregate emissions with all other factors held constant. Yet, IPM (as used by EPA) predicts that in just five months Entergy and other Louisiana and Mississippi electric companies will operate their generating units in a manner that will reduce NOx emissions by 42% and 37% below current actual emission levels, respectively. *See* Table 1, below. This is simply not possible.

Table 1

State	2010 Emissions	2012 Base Case	Difference
Louisiana	23,172	13,433	9,739
Mississippi	16,089	10,161	5,928

The IPM, at least as used here, does not address regional and local transmission constraints, voltage support requirements, load pocket issues and reliability rules imposed on transmission systems, which require certain units to run. Must run units supply critical voltage support and electricity in load pockets that have no access to other supplies. The power generated by these units cannot be substituted or compensated for without a substantial expansion or upgrade of the transmission systems or the construction of additional local generation, neither of which can be completed by May 1, 2012.[4] Because of these limitations in the IPM, the model failed to account for the fact that Entergy's units in Louisiana, Mississippi and Arkansas must run for reliability purposes and severely underestimated the base case emissions for these states. The resulting state emission budgets and source specific allocations are significantly below the level needed to meet the demand for electricity in Louisiana, Mississippi and Arkansas. Thus, the state budgets in the CSAPR are arbitrary and capricious and bear no rational connection to actual unit operations in those states, actual emissions and control installations.

In discussions since the promulgation of CSAPR, Entergy has brought to EPA's attention the serious limitations in the IPM's ability to integrate transmission constraints into its economic analysis. By letters dated September 20, 2011 and September 29, 2011, Entergy provided a comprehensive summary of the Entergy transmission system and a description of the limitations on the transmission system to import significant bulk power from beyond the system and to move energy and power within the Entergy System. The Entergy transmission system, as all

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[3] We understand that IPM does include emission limitations imposed by permit.

[4] Reliability modeling conducted by Southwest Power Pool ("SPP") the Regional Transmission Organization or Independent Coordinator of Transmission for utility companies in nine states, including in Louisiana, Mississippi, Arkansas, and Texas, "indicates that the CSAPR Integrated Planning Model 4.1 (IPM) results, as depicted by the EPA, are likely to cause SPP to be out of compliance with the applicable NERC standards as early as 2012." See SPP Letter to Lisa Jackson, pg. 1 (Sept. 20, 2011) (Attached as Exhibit H). SPP's reliability modeling removed all generation units that were assigned zero utilization by the IPM, such as the 23 units owned and operated by Entergy. SPP Letter to Lisa Jackson, pg. 1, n. 2 (Sept. 20, 2011) (Ex. H).

transmission systems, was constructed to ensure reliable electric supplies to its load centers based on its generation system. While the transmission system was designed to allow emergency and economic transmission among and between systems and regions, it was not designed for large bulk power transfers to displace existing generation. The system has capacity limits and congestion constraints that limit the flow of power to and from other transmission systems and within the sub-regions of the Entergy transmission system. The September 20 and 29, 2011, letters from Entergy are attached for your further review.[5] We also attach the underlying documentation that further supports the demonstration that EPA's application of the IPM failed to account properly for the limitations on Entergy transmission and generation system. Entergy also supplied to EPA by Entergy after the finalization of CSAPR.[6]

While the D.C. Circuit generally has deferred to EPA and its use of IPM modeling, the current application, and its limited, is flawed so seriously as to call into question such deference. "An agency's use of a model is arbitrary if that model bears no rational relationship to the reality it purports to represent." *Columbia Falls Aluminum Co. v. EPA*, 139 F.3d 914, 923 (D.C. Cir. 1998); *see also, Appalachian Power Co. v. EPA*, 249 F.3d 1032, 1053 (D.C. Cir. 2001) (citing *Chemical Mfrs. Ass'n v. EPA*, 28 F.3d 1259, 1265 (D.C. Cir. 1994)) ("While courts routinely defer to agency modeling of complex phenomena, model assumptions must have a 'rational relationship' to the real world.").

D. Louisiana, Mississippi, and Arkansas Should Not Be Included In CSAPR, As They Do Not Significantly Contribute To Nonattainment.

In CSAPR, EPA defines "significant contribution" under Section 112(a)(2)(D)(i)(I) by reference to (1) a state's "linkage" to down-wind receptors (i.e. emissions of approximately 1% of compliant ambient levels) and (2) the ability of the state to achieve highly cost effective emission reductions (below $500 per ton). *See* 76 Fed. Reg. 48,248. EPA states that only if emissions from a state are "linked" to a downwind receptor *and* the state can achieve emission reductions at costs below EPA's cost-effectiveness threshold is a state included in CSAPR. *See* 76 Fed. Reg. 48,248-49.

In CSAPR, EPA concluded that emissions from Louisiana, Mississippi and Arkansas were linked to the Houston/Galveston nonattainment area and that Mississippi and Arkansas were linked to the East Baton Rouge nonattainment area. However, EPA also concluded that no NOx emission reductions could be achieved below the base case at the $500 per ton threshold in any of those states. *See* 76 Fed. Reg. 48,263. Rather than exclude the three states from CSAPR, EPA decided to include Louisiana, Mississippi and Arkansas in the ozone season NOx trading program because of concern that "if emissions limits were not established for these ... states, ozone-season NOx emissions in each of the states would increase (beyond 2012 base case emission projections), due to inter-state shifts in electricity generation that cause 'emissions leakage.'" 76 Fed. Reg. 48,263. Thus, for the first time, EPA defines significant contribution for these three states (plus Indiana and Maryland) in a manner that is different than for all other

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[5] *See* Entergy Letter to EPA (Sept. 20, 2011) (Attached as Exhibit I); Entergy Letter to EPA (Sept. 29, 2011) (Attached as Exhibit J).

[6] The documents, labeled as Exhibits K - Q, are attached.

states. Based on EPA's definition, Louisiana, Mississippi and Arkansas should be removed from CSAPR because the states do not significantly contribute to downwind nonattainment or interfere with maintenance.

1. There are no NOx emissions reductions available in Louisiana, Mississippi, and Arkansas at the $500/ton significance threshold.

EPA contends that for Louisiana, Mississippi and Arkansas, significant contribution is "the difference between these states' projected emissions if they were not covered under the Transport Rule (but other states were), and their emissions after all emissions *that can be eliminated at $500/ton are prohibited.*" 76 Fed. Reg. 48,263. That is, EPA projects that if Louisiana, Mississippi and Arkansas are excluded, they would sell electricity to covered states and those states would not achieve the $500/ton reductions the IPM predicts. EPA does not suggest that Louisiana, Mississippi and Arkansas can achieve cost-effective emission reductions, nor do the suggest that avoiding increased emissions can be achieved at $500 per ton.

EPA's determination suffers from the same infirmities that caused it to understate the state budgets: EPA's use of the IPM does not address and assess critical transmission limitations and has misspecified cost inputs. As was demonstrated in the documents provided to EPA, and attached as Exhibits K-Q, Entergy cannot import unlimited quantities of "low emission" power into its system, nor can it move bulk power from system to neighboring utilities and transmission systems. The transmission constraints serve as a physical limitation on potential "leakage" that the IPM is simply incapable of assessing. Unless EPA corrects the IPM to account for the transmission constraints on Entergy's system, recognize the essential generating units on the Entergy system and correct the cost inputs, EPA cannot reach a reasoned conclusion that there would be "leakage" from these states. Until and unless EPA makes these corrections and changes, EPA cannot reasonably assess the cost-effectiveness of any emissions reductions or avoided increases from Louisiana, Mississippi and Arkansas.

2. There is no "link" between Louisiana and the Houston/Galveston nonattainment area.

The entire basis for including Louisiana in CSAPR is EPA's determination that Louisiana emissions of NOx "significantly impact" the ability of the three monitors in the Houston/Galveston area to attain the 1997 ozone NAAQS and "interfere with maintenance" of that standard for two additional monitors in the area. *See* 76 Fed. 48,263. EPA's determination depends on flawed data that significantly overestimates ozone season emissions in Louisiana. If EPA had relied on accurate data from Louisiana's Emissions Inventory, EPA's model likely would have shown that Louisiana does not interfere with the Houston/Galveston area's ability to attain or maintain the 1997 ozone standards.

The Houston/Galveston area achieved attainment with the 1997 Ozone NAAQS in 2009 and remained in attainment in 2010. There are 21 monitors within the Houston/Galveston area. EPA projected that Louisiana emissions affect five monitors out of those 21. *See* Tables 2, 3, below.[7] Four of the five monitors allegedly impacted by Louisiana emissions have had design

[7] Note: Bolded values indicate contributions exceeding the threshold of .8 ppb.

values below the ozone standard for at least three years. Three of these four have current design values more than 10 ppb below the standard, and are clearly unaffected by Louisiana emissions. The fifth monitor was in compliance with the standard during 2009 and 2010, but preliminary, uncertified data indicate that it now may have a design value just one part per billion over the standard.[8] In these circumstances, EPA's reliance on modeled results to include Louisiana in CSAPR, instead of readily accessible and accurate data, is arbitrary and capricious. *See Appalachian Power Co. v. EPA*, 249 F.3d 1032, 1054 (D.C. Cir. 2001) (finding that EPA acted arbitrarily in failing to "address[] what appear[s] to be stark disparities between its projections and real world observations"). The actual NAAQS data demonstrates that Louisiana's emissions are not interfering with maintenance in Texas.

Table 2: Louisiana's 8-hour Ozone Contributions (ppb) to Nonattainment Receptors - 2012 Base Case

Receptor #	**State**	**County**	**LA**
480391004	TX	Brazoria	**7.9**
482010051	TX	Harris	**7.3**
482010055	TX	Harris	**8.0**

Table 3: Louisiana's 8-hour Ozone Contributions (ppb) to Maintenance Receptors - 2012 Base Case

Receptor #	**State**	**County**	**LA**
90011123	CT	Fairfield	0.1
90093002	CT	New Haven	0.1
240251001	MD	Harford	0.0
260050003	MI	Allegan	0.3
482010029	TX	Harris	**5.8**
482011050	TX	Harris	**11.1**

EPA's modeled prediction of Louisiana emissions interfering with Texas attainment is unsupportable. The total NOx emissions used in the final rule's air quality modeling significantly exceeds the total NOx in the Louisiana emissions inventory: 499,359 tons of NOx. The Louisiana inventory has been certified and accepted for purposes of ozone modeling by EPA Region 6 and is based on correct use of all EPA protocols; there is no basis for EPA to rely on projected emissions data rather than currently accurate and certified data. Yet, in its air quality modeling, EPA used a projected total NOx amount of 626,542 tons of NOx from Louisiana, which exceeds the Louisiana Emissions Inventory by more than 125,000 tons of NOx emissions.[9] Because roughly half of these emissions occur during ozone season, the EPA ozone

[8] There is additional evidence indicating that this monitor, the Manvel Croix monitor in Brazoria County, is not impacted by Louisiana. *See* Comments by Lafayette Utilities System (Aug. 19, 2011) (Attached as Exhibit R).

[9] *See* EPA, Technical Support Document for Final Emissions Inventory, located at http://www.epa.gov/airtransport/pdfs/EmissionsInventory.pdf.

season projection is approximately 60,000 to 70,000 tons greater than actual emissions.[10] EPA projects Louisiana's NOx emissions for 2012, with EGUs subject to CSAPR, will be 497,774 tons per year. Had EPA used the Louisiana Emissions Inventory, rather than its projected emissions inventory, in its the air quality modeling, it is unlikely that EPA would have found "linkage" with Texas.

IV. CONCLUSION

For the reasons discussed above, Entergy urges EPA to reconsider and stay CSAPR to provide all stakeholders with an opportunity to comment on the revised state budgets. Entergy urges EPA to re-run the IPM with improved and corrected inputs so that the model more closely reflects reality. Entergy also urges EPA provide additional time before the effective date of the rule to allow sources sufficient time to install appropriate emission controls. Finally, Entergy urges EPA to remove Louisiana, Mississippi and Arkansas from the CSAPR and reconsider the late addition of Texas to both the annual NOx and SO_2 programs.

Dated: October 7, 2011

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On Behalf of Entergy Corporation

[10] A more in-depth analysis of the flaws in the emissions inventory data used by EPA in its air quality modeling can be found in comments by the Lafayette Utilities System. *See* Ex. R at pgs. 10-12. *See also*, Comments by Louisiana Chemical Association, Dkt No. EPA-HQ-OAR-2009-0491-3527 (Oct. 1, 2010) (Excerpt attached as Exhibit S).

Exhibit A

BEFORE THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In re:	§	
	§	EPA Docket No.
Federal Implementation Plans: Interstate	§	
Transport of Fine Particulate Matter and	§	EPA-HQ-OAR-2009-0491
Ozone and Correction of SIP Approvals,	§	
76 Fed. Reg. 48,208 (Aug. 8, 2011)	§	

PETITION FOR RECONSIDERATION AND STAY

Pursuant to 5 U.S.C. § 705 and 42 U.S.C. § 7607(d)(7)(B), the State of Texas, by and through its Attorney General, and on behalf of the Texas Commission on Environmental Quality ("TCEQ"), the Public Utility Commission of Texas, the Railroad Commission of Texas, the Texas Department of Agriculture, and the Texas General Land Office ("Texas," collectively) request reconsideration and an immediate stay of the above-referenced rule (the "Final Rule") as it applies to Texas.

INTRODUCTION

During the notice-and-comment period, TCEQ and several private parties commented on the proposed version of the Final Rule based on the limited Texas-relevant information that was available at the time. When the Final Rule was promulgated, Texas was surprised, and dismayed, to discover that the previously disclosed information on which TCEQ commented was no longer relevant and that the Final Rule would have a significant impact on Texas in ways that could not possibly have been foreseen during the notice-and-comment period.

Texas now provides the following comments and urges EPA to grant a reconsideration proceeding and a stay of the Final Rule's effective date and compliance deadlines as they apply to Texas. As explained below, failure to do so would not only violate the notice requirements of both the Administrative Procedure Act, 5 U.S.C. § 551-59 ("APA") and the Clean Air Act, 42 U.S.C. § 7401-7700 ("CAA"), but it would also allow a rule that violates substantive provisions of the CAA to remain on the books. In light of the Final Rule's significant flaws and the pronounced detrimental effects that its implementation will have, the Administrator should grant this request for reconsideration and an immediate stay of the rule as it applies to Texas.

BACKGROUND

I. Statutory Framework

The CAA requires the United States Environmental Protection Agency ("EPA") "to issue national ambient air quality standards ('NAAQS') for each air pollutant that 'cause[s] or contribute[s] to air pollution which may reasonably be anticipated to endanger public health or welfare [and] the presence of which in the ambient air results from numerous or diverse mobile or stationary sources.'" *North Carolina v. EPA*, 531 F.3d 896, 901 (D.C. Cir. 2008) (quoting 42 U.S.C. § 7408(a)(1)(A), (B)). Once EPA establishes NAAQS, the CAA requires EPA, after consultation with the States, to designate areas as "nonattainment," "attainment," or "unclassifiable." 42 U.S.C. § 7407(c), (d).

The statute provides States with important rights and responsibilities with respect to EPA's actions. After the issuance of NAAQS, States are required to develop state implementation plans ("SIPs") to meet them. *Id.* § 7410(a)(1). Generally speaking, States enjoy wide latitude when determining how areas within their borders will attain and maintain NAAQS. *Train v. Natural Res. Defense Council, Inc.*, 421 U.S. 60, 86-87 (1975); *see Union Elec. Co. v. EPA*, 427 U.S. 246, 269 (1976) (explaining that "Congress plainly left with the states, so long as the [NAAQS] were met, the power to determine which sources would be burdened by regulation and to what extent").[1]

Of particular relevance to this proceeding is the CAA's "good neighbor" provision, 42 U.S.C. § 7410(a)(2)(D)(i)(I). Under that provision, States are required to "prohibit[] . . . any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will . . . contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any . . . national primary or secondary ambient air quality standard." *Id.*

II. The Proposed and Final Versions of the Rule

In early August 2010, EPA published the "Clean Air Transport Rule," the proposed rule on which the Final Rule is based. Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, Proposed Rule, 75 Fed. Reg. 45,210 (Aug. 2, 2010) (the "Proposed Rule"). The Proposed Rule announced EPA's intent to issue federal implementation plans ("FIPs") that would "limit the interstate transport of emissions of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) . . . within 32 states in the eastern United States that affect the ability of downwind states to attain and maintain compliance with the 1997 and 2006 fine particulate matter ($PM_{2.5}$) . . . NAAQS and the 1997 ozone NAAQS." *Id.* at 45,210; *see also* Luminant's Petition for Reconsideration and Stay at 8-10, Docket No. EPA-HQ-OAR-2009-0491 (Aug. 5, 2011) ("Luminant PFR") (providing a more detailed account of the Proposed Rule).[2]

Significantly, the Proposed Rule did not include the State of Texas among the "25 jurisdictions that contribute significantly to nonattainment in, or interfere with maintenance by, a downwind area with respect to the 24-hour $PM_{2.5}$ NAAQS promulgated in September 2006." Proposed Rule, 75 Fed. Reg. at 45,215. Nor was Texas included among the "24 jurisdictions that contribute significantly to nonattainment in, or interfere with maintenance by, a downwind area with

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1. TCEQ (formerly the Texas Natural Resource Conservation Commission) has primary responsibility for implementing and overseeing Texas's CAA obligations, including compliance with the requirement to implement, maintain, and enforce NAAQS through SIPs. *See generally* TEX. HEALTH & SAFETY CODE ch. 382; *id.* § 382.0173(a).

2. To avoid repetition of information that has already been presented to EPA, Texas incorporates the cited portions of other parties' filings by reference.

respect to the annual $PM_{2.5}$ NAAQS promulgated in July 1997." *Id.* The Proposed Rule announced an intent to require Texas to reduce only its "ozone season NO_X emissions . . . that contribute significantly to nonattainment in, or interfere with maintenance by, a downwind area with respect to the 1997 ozone NAAQS promulgated in July 1997." *Id.*

The Final Rule, however, is very different from the Proposed Rule. Instead of targeting only ozone-season NO_X emissions for Texas, as the Proposed Rule had done, the Final Rule also targets annual NO_X emissions, as well as SO_2 emissions. The Final Rule does so based on EPA's finding—made for the first time in the Final Rule—that Texas contributes significantly to downwind nonattainment with respect to the 1997 Annual $PM_{2.5}$ NAAQS. Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 Fed. Reg. 48,208, 48,213-14 (Aug. 8, 2011) (the "Final Rule"). It also establishes a FIP for ozone and annual $PM_{2.5}$ only and specifies emission budgets for Texas for annual SO_2, annual NO_X, and ozone-season NO_X, *id.* at 48,262-63 (Tables VI.D-3, VI.D-4), requiring Texas electric generating units ("EGUs") to comply with specific emission allocations beginning January 1, 2012, *id.* at 48,211—less than five months after the Final Rule was published in the Federal Register. *Id.* at 48,208 (published August 8, 2011).

The inclusion of Texas in the Final Rule is based on modeling, which EPA presented for the first time in the Final Rule, predicting that Texas will, in 2012, contribute significantly to $PM_{2.5}$ nonattainment at a single air-pollution monitoring site: the Granite City site in Madison County, Illinois. *Id.* at 48,213, 48,240 (Tables V.D-1, V.D-2, V.D-3, V.D-4). EPA concluded that, because its model of Texas's annual $PM_{2.5}$ contribution (0.18 $\mu g/m^3$, *see id.* at 48,240 (Table V.D-1)) predicts exceedance of the relevant significance threshold (0.15 $\mu g/m^3$, *id.* at 48,236), Texas should be required to reduce the emissions that would purportedly lead to this modeled contribution.[3]

This was true even though, as already noted, the Proposed Rule had not found Texas to be contributing significantly to either the annual or 24-hour $PM_{2.5}$ standard. Proposed Rule, 75 Fed. Reg. at 45,215; *see id.* at 45,255, 45,261 (Tables IV.C-13, IV.C-16) (listing Texas's largest contribution to downwind annual $PM_{2.5}$ nonattainment as 0.13 $\mu g/m^3$, to downwind annual $PM_{2.5}$ maintenance-interference as 0.06 $\mu g/m^3$, to downwind 24-hour $PM_{2.5}$ nonattainment as 0.21 $\mu g/m^3$, and to downwind 24-hour $PM_{2.5}$ maintenance-interference as 0.28 $\mu g/m^3$). Indeed, the Proposed Rule had called for comment on whether Texas should be included in the Final Rule on just one basis: the prospect that exclusion of Texas from the Final Rule's scope would reduce the price to Texas EGUs of high-sulfur coal, which in turn could cause the EGUs that purchased and burned that coal to begin contributing significantly to downwind nonattainment and maintenance-interference in other States. *Id.* at 45,284. TCEQ and others provided comments critical of that proposed basis for including Texas, and EPA ultimately abandoned it, choosing to include Texas in the Final Rule based on new modeling significantly linking Texas to the Granite City monitor.

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3. EPA specifies in the Final Rule that it is not adopting a FIP for Texas with respect to the 24-hour $PM_{2.5}$ NAAQS. *See id.* at 48,214. But EPA also clearly acknowledges, in setting Texas's emissions budgets, that those budgets will address significant contributions for the 24-hour $PM_{2.5}$ NAAQS. *See id.*

And although that modeling suggested, to EPA, that Texas would just barely exceed the relevant significance threshold (by 0.03 $\mu g/m^3$ for annual $PM_{2.5}$ contribution, *see* Final Rule, 76 Fed. Reg. at 48,240-242 (Tables V.D-1, V.D-4)), the Final Rule's previously undisclosed emissions budgets for Texas mandated substantial reductions in both annual NO_X and SO_2. *Id.* at 48,269. As noted below, the required reductions for Texas were more onerous than those for other States whose significant contributions to downwind nonattainment and maintenance-interference far exceeded Texas's modeled contributions.

Reasons to Convene a Reconsideration Proceeding and Grant a Stay

Under the CAA, EPA's Administrator has no choice but to reconsider the Final Rule. The statute directs that the Administrator "shall convene a proceeding for reconsideration" if two showings are made: *first*, that it was either impracticable to raise the relevant objection during the comment period or the grounds for such objection arose after the period for public comment (but within the time specified for judicial review), and *second*, that the objection is of central relevance to the outcome of the rule. 42 U.S.C. § 7607(d)(7)(B). Each of those elements is satisfied here.

On the first point, the Final Rule is so fundamentally different from the Proposed Rule, and predicated on such fundamentally different grounds than the Proposed Rule, that it could not possibly be viewed as a logical outgrowth of the Proposed Rule. *See infra* Part I; *see also* Luminant PFR at 4-5 (quoting the Office of Management and Budget's ("OMB's") report on interagency review, which noted that the Final Rule was a "significantly different rule than originally proposed," Summary of Interagency Working Comments on Draft Language under EO 12866 Interagency Review ("OMB Summary of Interagency Working Comments"), Document EPAHQ-OAR-2009-0491-4133 at 11 (posted July 11, 2011)). Although TCEQ provided some comments during the public-comment period and in response to EPA's Notices of Data Availability ("NODAs"), neither it nor any other party could have provided comment on the core elements of the Final Rule as it relates to Texas because those elements were not disclosed until the Final Rule was promulgated.

On the second point, the objections raised in this petition are of central relevance to the outcome of the rule because they reflect the Final Rule's legal invalidity on multiple grounds. For that reason, the Administrator must "convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed." 42 U.S.C. § 7607(d)(7)(B).

I. Texas did not have adequate notice or a meaningful opportunity to comment.

A. The law on notice is well-settled and, if EPA does not grant reconsideration, Texas's lack of notice will be a basis for vacating the Final Rule on judicial review.

In "afford[ing] interested parties a reasonable opportunity to participate in the rulemaking process," *Am. Radio Relay League, Inc. v. FCC*, 524 F.3d 227, 236 (D.C. Cir. 2008) (internal quotation mark omitted), adequate notice is fundamental to sound administrative decision-making. The notice requirement is "designed (1) to ensure that agency regulations are tested via exposure to diverse public comment, (2) to ensure fairness to affected parties, and (3) to give affected parties an opportunity to develop evidence in the record to support their objections to the rule and thereby enhance the quality of judicial review." *Int'l Union, United Mine Workers of Am. v. Mine Safety & Health Admin.*, 407 F.3d 1250, 1259 (D.C. Cir. 2005) (citing *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 547 (D.C. Cir. 1983)).

Here, two statutes required EPA to provide Texas and other interested parties adequate notice of the rule and its underlying support. The APA required EPA to publish, in the Federal Register, a notice of proposed rulemaking that included "either the terms or substance of the proposed rule or a description of the subjects and issues involved." 5 U.S.C. § 553(b)(3). And the CAA required EPA to take the additional, and more detailed, step of providing a statement of the Proposed Rule's basis and purpose that included "a summary of—(A) the factual data on which the proposed rule [wa]s based; (B) the methodology used in obtaining the data and in analyzing the data; and (C) the major legal interpretations and policy considerations underlying the proposed rule." 42 U.S.C. § 7607(d)(3); *see Small Refiner*, 705 F.2d at 518-19 (discussing the requirements of CAA section 7606(d)(3)).

As the D.C. Circuit has frequently explained, a proposed rule and a final rule may permissibly differ "only insofar as the latter is a 'logical outgrowth' of the former." *Envtl. Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005) (citing *Shell Oil Co. v. EPA*, 950 F.2d 741, 750-51 (D.C. Cir. 1991)), and a final rule is a "logical outgrowth" of a proposed rule only if interested parties "'should have anticipated' that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *Ne. Md. Waste Disposal Auth. v. EPA*, 358 F.3d 936, 952 (D.C. Cir. 2004) (quoting *City of Waukesha v. EPA*, 320 F.3d 228, 245 (D.C. Cir. 2003)). Stated differently, "a final rule will be deemed the logical outgrowth of the proposed rule if a new round of notice and comment would not provide commentators with their first occasion to offer new and different criticisms which the agency might find convincing." *Fertilizer Inst. v. EPA*, 935 F.2d 1303, 1311 (D.C. Cir. 1991) (internal quotation marks omitted).

In light of these requirements, notice is adequate only if it allows interested parties a chance to provide "meaningful" comments, and comments can be meaningful only if parties are made aware of what, specifically, they need to comment on. *See Gerber v. Norton*, 294 F.3d 173, 179 (D.C. Cir.

2003) (finding no meaningful opportunity to comment on a permit that was linked to the mitigation value of an undefined mitigation site); *see also Small Refiner*, 705 F.2d at 518-19, 548 (discussing "Congress' intent, expressed in [CAA] § 307(d), that EPA provide a detailed proposal for interested parties to focus their comments on"). "If the APA's notice requirements mean anything, they require that a reasonable commenter must be able to trust an agency's representations about which particular aspects of its proposal are open for consideration." *Envtl. Integrity Project*, 425 F.3d at 998 (citing *Fertilizer Inst.*, 935 F.2d at 1312).

Adequate notice is particularly important when an agency relies on scientific studies or data in support of a final rule. As the D.C. Circuit has explained, "[i]ntegral to the notice requirement is the agency's duty 'to identify and make available technical studies and data that it has employed in reaching the decisions to propose particular rules .... An agency commits serious procedural error when it fails to reveal portions of the technical basis for a proposed rule in time to allow for meaningful commentary.'" *Solite Corp. v. EPA*, 952 F.2d 473, 484 (D.C. Cir. 1991) (quoting *Conn. Light & Power Co. v. NRC*, 673 F.2d 525, 530-31 (D.C. Cir. 1982)); *see Sierra Club v. Costle*, 657 F.2d 298, 334, 397-98 & n.484 (D.C. Cir. 1981) (describing public notice and comment regarding relied-upon technical analysis as "safety valves in the use of . . . sophisticated methodology").

Along these same lines, the D.C. Circuit has explained that "[i]t is not consonant with the purpose of a rule-making proceeding to promulgate rules on the basis of inadequate data, or on data that, [to a] critical degree, is known only to the agency." *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 393 (D.C. Cir. 1973). For that reason, post-comment publication of the key methodology underlying a rule cannot provide adequate notice where that methodology is an integral part of the agency's model. *Owner-Operator Indep. Drivers Ass'n v. Fed. Motor Carrier Safety Admin.*, 494 F.3d 188, 201-02 (D.C. Cir. 2007); *see Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1030-31 (D.C. Cir. 1978).

Generally, an agency must *itself* satisfy the notice requirement, rather than rely on third parties' comments on a rule to do so indirectly. *Small Refiner*, 705 F.2d at 549 (explaining that "the EPA must itself provide notice of a regulatory proposal. Having failed to do so, it cannot bootstrap notice from a comment."); *see McLouth Steel Prods. Corp. v. Thomas*, 838 F.2d 1317, 1323 (D.C. Cir. 1988). In *Small Refiner*, the court recognized that a contrary rule "would turn notice into an elaborate treasure hunt, in which interested parties . . . must search the record for the buried treasure of a possibly relevant comment." 705 F.2d at 550; *see, e.g., AFL-CIO v. Donovan*, 757 F.2d 330, 340 (D.C. Cir. 1985).

Under the CAA, a notice violation will result in a rule's reversal so long as there is "a substantial likelihood that the rule would have been significantly changed if [the complained-of] errors had not been made." 42 U.S.C. § 7607(d)(8); *Small Refiner*, 705 F.2d at 521-24, 543-44 & n.102, 550. And "failure to observe the basic APA procedures, if reversible error under the APA, is reversible error under the [CAA] as well." *Small Refiner*, 705 F.2d at 523. Challengers must present "enough to show that on remand they can mount a credible challenge to the amended rule and were thus prejudiced by the absence of an opportunity to do so before the amendment." *Util.*

Solid Waste Activities Group v. EPA, 236 F.3d 749, 755 (D.C. Cir. 2001); *but see also McLouth*, 838 F.2d at 1324 (noting that requiring a showing of prejudice "is normally inappropriate where the agency has completely failed to comply with [APA] § 553").

As shown below, EPA failed to comply with both APA section § 553(b) and CAA section § 7607(d)(3) with respect to Texas's inclusion in the Final Rule. EPA should grant reconsideration and a stay to save the rule from vacatur on this basis. *See, e.g.*, *Envtl. Integrity Project*, 425 F.3d at 998; *Int'l Union*, 407 F.3d at 1261.

B. The lack of notice prevented Texas from providing comments that would have significantly changed the Final Rule.

1. Because the Proposed Rule gave Texas no notice that it would be significantly linked to a $PM_{2.5}$ monitor for nonattainment, Texas had no opportunity to identify the errors underlying its linkage, in the Final Rule, to the Granite City monitor.

As already noted, the Proposed Rule did not identify any Texas linkage to nonattainment or maintenance-interference monitors for $PM_{2.5}$, nor was Texas included in the proposed $PM_{2.5}$ FIP. *See* Proposed Rule, 75 Fed. Reg. at 45,632-33. In the Proposed Rule, EPA provided estimated interstate contributions to annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and 8-hour ozone nonattainment and maintenance-interference for each of 37 states. *Id.* at 45,255 (Table IV.C-13). Texas's largest downwind contribution to nonattainment for annual $PM_{2.5}$ was 0.13 $\mu g/m^3$. These downwind contributions were calculated for each State with respect to each of the 32 monitoring sites that were projected to reflect nonattainment status and each of the 16 sites projected to reflect maintenance problems for the annual $PM_{2.5}$ NAAQS in the 2012 base case. *Id.* at 45,255. Because Texas's largest downwind contribution did not exceed EPA's 0.15 $\mu g/m^3$ significance threshold, *see id.* (Table IV.C-13), the Proposed Rule did not significantly link Texas to any annual $PM_{2.5}$ monitor receptor, and Texas was therefore not required to make any emissions reductions to meet the annual $PM_{2.5}$ NAAQS. *See id.* at 45,216 (Table III.A-1).

It was impossible and impractical, based on the limited information provided through the Proposed Rule, for the State to comment on the potential significant contribution of Texas for the annual $PM_{2.5}$ NAAQS. This is especially true in light of the different monitor-receptor projections regarding future nonattainment, maintenance-interference, or both and the photochemical modeling that appeared in the Final Rule but was never previously made available for public review and comment. *Compare, e.g.*, Proposed Rule, 75 Fed. Reg. at 45,246-251, *and id.* at 45,253-260 *with* Final Rule, 76 Fed. Reg. at 48,233-244. The Final Rule's scientific and technical underpinnings were so vastly different in both nature and scope that Texas could not have "guessed" that it would be modeled to contribute significantly with respect to any downwind area, much less for any particular NAAQS. In short, it was impossible for TCEQ or any other party to comment on the particular $PM_{2.5}$ monitor to which Texas was significantly linked in the Final Rule because that monitor was not identified, in the Proposed Rule, as a nonattainment monitor that Texas might significantly affect.

Had Texas been aware of this linkage, it would have submitted comments addressing problems with the Granite City monitor, as another commenter has now done. *See* Luminant PFR at 16-19. That monitor is inappropriate for at least two reasons. First, it is currently in attainment of the annual $PM_{2.5}$ NAAQS. *See* Approval and Promulgation of Air Quality Implementation Plans; Illinois; Missouri; Saint Louis Nonattainment Area; Determination of Attainment of the 1997 Annual Fine Particle Standard, 76 Fed. Reg. 29652 (May 23, 2011). Second, the Granite City monitor is heavily influenced by local conditions— specifically, the close proximity of a steel mill, which is the proximate cause of any past exceedances of the $PM_{2.5}$ NAAQS. *See id.* at 29,653 ("EPA agrees that Madison County, Illinois monitors have generally recorded the highest ambient $PM_{2.5}$ concentrations in the Saint Louis area. In addition to monitor 17-119-1007, area high values have been recorded at monitor 17-119-0024. Both monitors are in Granite City near [the steel mill].").

In determining that the Granite City monitor was an appropriate nonattainment receptor, EPA ignored air-quality data from a federally approved regulatory monitor and, indeed, its own recent acknowledgment that this area is in attainment of the annual $PM_{2.5}$ NAAQS. Despite its language in the notice determining that this area is in attainment, *id.* (stating that "[m]onitored attainment of the standard is the only basis of a determination of attainment or nonattainment, and it is the only relevant issue"), EPA is ignoring monitored air-quality data in favor of a hypothetical modeling exercise to determine potential nonattainment receptors that do not fully consider current relevant conditions and air-quality controls. *See* Final Rule, 76 Fed. Reg. at 48,233-235 (explaining EPA's revised air-quality modeling). Texas could not have commented on this situation at the proposed-rule stage, as EPA did not propose to significantly link Texas to this particular monitor.[4] Further, EPA's final acknowledgment of attainment for the area in which this monitor is found was only published May 23, 2011, so TCEQ would not have had that information available to it at the time the Proposed Rule was published.

In neither its proposed or final determination of attainment notice for the St. Louis nonattainment area (in which the Granite City monitor is located) does EPA mention transport as a potential reason for either past or future nonattainment or for maintenance issues at the monitor. *See* Approval and Promulgation of Air Quality Plans; Illinois; Missouri; Saint Louis Nonattainment Area; Determination of Attainment of the Fine Particle Standard, Proposed Rule, 76 Fed. Reg. 12,302 (March 7, 2011); Approval and Promulgation of Air Quality Plans; Illinois; Missouri; Saint Louis Nonattainment Area; Determination of Attainment of the Fine Particle Standard, 76 Fed. Reg. 29,652 (May 23, 2011). This is in contrast to another recent EPA notice recommending that Baton

4. EPA provided a list of modeled linkages for all States analyzed in the Proposed Rule in its Air Quality Modeling Technical Support Document, but Texas was below the linkage threshold for both annual and 24-hour $PM_{2.5}$, and therefore no monitor was identified in the Proposal Rule for Texas to analyze and comment on. In the Final Rule, EPA made significant revisions to its modeling, *see* 76 Fed. Reg. at 48,253, and determined that Texas was significantly linked to the Madison County monitor (monitor number 171191007) for both 24-hour and annual $PM_{2.5}$.

Rouge, Louisiana be redesignated to attainment of the 1997 eight-hour ozone standard. *See* Approval and Promulgation of Implementation Plans and Designation of Areas for Air Quality Planning Purposes; Louisiana; Baton Rouge Ozone Nonattainment Area: Redesignation to Attainment for the 1997 8-Hour Ozone Standard, 76 Fed. Reg. 53,853 (August 30, 2011). That notice contained a specific discussion of the reductions required by the Clean Air Interstate Rule ("CAIR"), and projected to be required by the Final Rule, and the role of those reductions in ensuring that Baton Rouge reached and will maintain the ozone standard. *Id.* at 53,868. Therefore, even if Texas had been able to divine EPA's intent to further investigate the Granite City monitor, it would not have had notice that EPA considered transport from Texas to be significantly contributing to the Granite City monitor. It is unreasonable that Texas is being required to make drastic emissions reductions for the purported purpose of ensuring that this monitor will attain the annual $PM_{2.5}$ standard.

Furthermore, EPA's use of the Granite City monitor as a nonattainment receptor for an upwind state is unreasonable on its face, due to heavy influence from its close proximity to a sizable steel mill. The steel mill ceased operation in 2008, and the monitor has since monitored attainment for both annual and 24-hour $PM_{2.5}$. *See* Saint Louis Determination of Attainment, 76 Fed. Reg. at 29,654. Although the mill resumed operations in 2010, its emissions are greatly reduced under a Memorandum of Understanding with the Illinois Environmental Protection Agency designed to prevent future attainment issues. "Assessment of Local-Scale Emissions Inventory Development by State and Local Agencies," Sonoma Technology, Inc. (October 2010), *available at* http://www.epa.gov/ttn/chief/local_scale/sti_epa_local_scale_ei_final_report.pdf, and appx. B, "Presentations by State and Local Agencies to the Local-Scale Emissions Focus Group," 89-127, *available at* http://www.epa.gov/ttn/chief/local_scale/sti_epa_local_scale_ei_final_report_appendices.pdf; "United States Steel Corporation Granite City Works and IEPA Memorandum of Understanding," signed July 1, 2010.

The Final Rule also provides a precedent to consider the effects of local controls in calculations of upwind States' significant contributions to this monitor. But EPA applies the consideration of local contribution in the Final Rule arbitrarily. A monitor in Allegheny County, Pennsylvania, is located downwind from a large coking unit. Final Rule, 76 Fed. Reg. at 48, 247, n.40. The Allegheny County monitor is located approximately the same distance from the coking unit as the Granite City monitor is to the steel mill. Even though the Allegheny County monitor continued to show maintenance issues after the $2,300/ton reductions were applied, EPA did not increase the cost threshold to require emissions reductions from any upwind State, due to the heavy local influence on the Allegheny County monitor.[5] Similarly, States linked to the Granite City monitor should not be shifted to a new cost threshold (in this case, from $0.00 to $500.00/ton) and

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5. Final Rule, 76 Fed. Reg. at 48,259. EPA stated: "It is well-established that, in addition to being impacted by regional sources, the Liberty-Clairton area is significantly affected by local emissions from a sizable coke production facility and other nearby sources, leading to high concentrations of organic carbon in this area. EPA finds that the remaining $PM_{2.5}$ nonattainment problem is predominantly local and therefore does not believe that it would be appropriate to establish a higher cost threshold solely on the basis of this projected ongoing nonattainment of the 24-hour $PM_{2.5}$ standard at the Liberty-Clairton receptor." *Id.*

required to reduce emissions due to the heavy local influence on the Granite City monitor. EPA provides no rationale for why the Granite City monitor is treated differently from the Allegheny County monitor.

Had the EPA considered more recent monitoring data at the Granite City monitor (which would incorporate the effects of local, non-CAIR controls on this primarily locally influenced monitor), it would have found that the monitor was in attainment and would continue to be in attainment without the Final Rule's controls. At a minimum, had EPA still chosen to include this monitor as a nonattainment receptor, by considering local influences at the monitor, it should have selected a cost threshold lower than $500/ton when calculating significant contribution.

Therefore, the use of a modeled linkage showing a significant contribution between Texas and the Granite City monitor is unreasonable and was not supported in the Final Rule by any rational reason. EPA should reconsider the appropriateness of the Granite City monitor for use in evaluating upwind significant contributions because it is actually demonstrating attainment through air-quality monitor data and the monitor is heavily influenced by the local steel mill. Additionally, even if the Madison County monitor were an appropriate receptor for consideration, EPA should reconsider the appropriate cost threshold for evaluating significant contribution and required emissions reductions.

If, as EPA has acknowledged in its determination of attainment for the St. Louis area, St. Louis will remain in attainment without any emissions reductions from Texas, then Texas cannot possibly be significantly contributing to nonattainment or maintenance-interference for this monitor. For these reasons alone, Texas was denied the reasonable opportunity to participate in the rulemaking process that the APA, the CAA, and the case law requires. *See supra* Part I.A. But as explained below, that is by no means the extent of the problem.

2. The Proposed Rule failed to provide adequate notice of key factual data and EPA's methodology, both of which the State would have challenged during the notice and comment period.

In the Proposed Rule, EPA noted that it was proposing a two-step approach to identify which States were significantly contributing to downwind nonattainment and maintenance-interference. Proposed Rule, 75 Fed. Reg. at 45,233-34. The first step was to utilize air-quality modeling to quantify individual state contributions to downwind nonattainment and maintenance-interference sites in 2012. *Id.* States whose contributions to any downwind site exceeded one percent of the relevant NAAQS were considered "linked" to the site. *Id.* In the second step, EPA identified the portion of each State's contribution that was considered "significant." *Id.* For this step, EPA used maximum cost thresholds with additional information from what it called "air quality considerations." *Id.* Basically, EPA determined what reductions were available from EGUs in an individual upwind State at a particular maximum cost threshold and required all of those emission reductions to be made without regard to what was actually required to eliminate a State's significant contribution to the downwind monitor receptor. *Id.* at 45,270-284. Therefore, the determination of the downwind monitor receptor sites was a critical factor in EPA's analysis and, as such, a crucial piece of information for a State to evaluate when gauging the possibility that it would significantly impact a particular monitor.

EPA first identified "all monitors projected to be in nonattainment, or based on historic variability in air quality, projected to have maintenance problems in 2012." *Id.* at 45,233.[6] The question this endeavor was to answer—whether any particular monitor was appropriately projected to be in nonattainment or have maintenance problems in 2012—was of obvious and critical importance to any State eventually found to be significantly contributing to another State's air pollution.

EPA reflected its own understanding of the importance of information regarding monitor linkages and the timely dissemination of that information to the States by providing six other States supplemental notice and an opportunity to comment on monitor linkages that either were not included in the Proposed Rule or were altered in the Final Rule. Federal Implementation Plans for Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin to Reduce Interstate Transport of Ozone, Proposed Rule, 76 Fed. Reg. 40,662 (July 11, 2011). Inexplicably, however, EPA failed to provide Texas with supplemental notice and the ability to comment on its purported significant linkage for nonattainment of the annual $PM_{2.5}$ standard to the Granite City monitor, which was likewise not disclosed in the Proposed Rule.

6. To do so, EPA considered all emissions reductions associated with the implementation of all federal rules promulgated by December 2008 and assumed that CAIR, a previous rule with a purpose similar to that of the Final Rule, had no effect. *Id.*; *see North Carolina*, 531 F.3d at 930 (vacating CAIR); *but see also North Carolina v. EPA*, 550 F.3d 1176, 1178 (D.C. Cir. 2008) (per curiam opinion on rehearing remanding the case to EPA without vacating CAIR).

Specifically, Iowa, Kansas[7], Michigan[8], Missouri, Oklahoma[9] and Wisconsin were all found to have new ozone linkages in the Final Rule and were therefore given a chance to comment. Final Rule, 76 Fed. Reg. at 48,244-246. Yet Texas, which the Proposed Rule did not significantly link to any monitors for $PM_{2.5}$, was afforded no opportunity for notice and comment regarding its significant contribution to any nonattainment receptor for $PM_{2.5}$. Additionally, and as already noted, the monitor on which EPA based its significant-contribution finding for Texas in the Final Rule is currently in *attainment* status. *See* Saint Louis Determination of Attainment, 76 Fed. Reg. at 29,652-53 (acknowledging that the Saint Louis $PM_{2.5}$ nonattainment area in Illinois and Missouri has attained the 1997 annual $PM_{2.5}$ NAAQS and that "[m]onitored attainment of the standard is the only basis of a determination of attainment or nonattainment, and it is the only relevant issue"); *see* Luminant PFR at 16-19. Had this link been identified in the Proposed Rule, Texas would have commented on several flaws in EPA's assumptions regarding the monitor and the propriety of its inclusion as a receptor. *See supra* Part I.B.1.

3. EPA's sole request for comment regarding Texas was misleading.

In the Proposed Rule, EPA not only failed to provide notice of key information regarding Texas's inclusion in the Final Rule, but it also asked for comments on what ultimately proved to be a non-issue. Whether intentionally so or not, this request was misleading, and it yielded comments from TCEQ and others that EPA later admitted were "no longer relevant." Transport Rule Primary Response to Comments at 562, Document No. EPA-HQ-OAR-2009-0491-4513 (June 2011); *see* Luminant PFR at 12-14.

At the rule-proposal stage, EPA requested comment on the potential inclusion of Texas with respect to $PM_{2.5}$ emissions—a request premised on the idea that the Final Rule would lead EGUs in

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7. Kansas was included in the ozone program at the proposed-rule stage (and thus provided a preliminary budget for review and comment) due to a linkage to Dallas County, TX (481130069), Proposed Rule, 75 Fed. Reg. at 45,269-270 (Tables IV.C.20, IV.C-21), that was subsequently dropped as a projected maintenance monitor in the Final Rule. Kansas was linked in the Final Rule to a new monitor (Allegan, MI (260050003)). Final Rule, 76 Fed. Reg. at 48,246 (Tables V.D.8, V.D-9).

8. Michigan was included in the ozone program at the proposed-rule stage (and thus provided a preliminary budget for review and comment) due to a linkage to Suffolk, NY (361030009). Proposed Rule, 75 Fed. Reg. at 45,269 (Table IV.C-20). The Suffolk monitor was dropped as a projected nonattainment monitor in the Final Rule, but Michigan was linked to a new monitor (Harford, MD (240251001)). Final Rule, 76 Fed. Reg. at 48,246 (Tables V.D.8, V.D-9).

9. Oklahoma was included in the ozone program at the proposed-rule stage (and thus provided a preliminary budget for review and comment) due to a linkage to a Tarrant County, TX nonattainment monitor (484391002), and to Dallas and Tarrant County, TX, maintenance monitors (481130069, 481130087, 484392003), Proposed Rule, 75 Fed. Reg. at 45,269-270 (Tables IV.C-20, IV.C-21), all of which were subsequently dropped as nonattainment and/or maintenance monitors in the Final Rule. Oklahoma was linked in the Final Rule to a new monitor (Allegan, MI (260050003)). Final Rule, 76 Fed. Reg. at 48,246 (Tables V.D.8, V.D-9).

covered jurisdictions to buy more low-sulfur coal, which in turn would decrease the demand for (and price of) higher-sulfur coal that Texas EGUs might then begin to buy and burn in quantities sufficient to yield significant emissions contributions in downwind States. Proposed Rule, 75 Fed. Reg. at 45,284. EPA's proposal predicted SO_2 emission increases of more than 5,000 tons for Texas and four other States. But because EPA's projected significance threshold was exceeded only for Texas, EPA requested comment only on the potential inclusion of Texas for this purpose. *Id.* (stating that "[f]urther analysis with the air quality assessment tool indicates that these projected increases in the Texas SO_2 emissions would increase Texas's contribution to an amount that would exceed the 0.15 $\mu g/m^3$ threshold for annual $PM_{2.5}$. For this reason, EPA takes comment on whether Texas should be included as a group 2 state.").[10]

EPA did not, however, identify any nonattainment or maintenance monitor as a potential receptor that could be affected by the anticipated increased use of high-sulfur coal. And because it requested comment only on the potential inclusion of Texas due to increased SO_2 emissions, specifically due to fuel switching, Texas could not reasonably have been expected to provide comments based on inclusion for any one of innumerable possibilities that were *not* proposed.

4. Because the Proposed Rule did not include emissions budgets for Texas, Texas had no opportunity to comment on the effects the Final Rule would have and identify problems that EPA should have considered.

The Final Rule's core premise is that the covered States must reduce their total emissions of NO_X and SO_2 to ensure that they do not contribute significantly to air pollution in downwind States. Final Rule, 76 Fed. Reg. at 48,209. To accomplish that goal, the rule sets emissions budgets that States may not exceed. *Id.* at 48,210. As already noted, EPA's data did not show Texas contributing significantly to any out-of-state monitor, so EPA did not propose emission budgets for Texas for annual NO_X or annual SO_2. Proposed Rule, 75 Fed. Reg. at 45,291 (Table IV.E-1); *id.* at 45,294-95 (Tables IV.F-1, 2); *see also* Luminant PFR at 14-16.

Because EPA did not propose emissions budgets for Texas, neither TCEQ nor any other party could comment on potential emissions-reduction requirements for Texas or other related issues. In the Final Rule, EPA suggests that it was unnecessary to provide illustrative budgets for States because EPA provided a proposed methodology for budget calculation that should be considered sufficient (suggesting that Texas should have calculated its own budget). Final Rule, 76 Fed. Reg. at 48,214. It is unclear, however, why Texas alone should have had to provide this independent assessment in order to understand and assess the impacts of the rule on the State and its EGUs.

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10. TCEQ and several other parties commented, in response to this request, on the infeasibility for many Texas EGUs to switch to higher-sulfur coals, making it improbable that Texas SO_2 emissions would increase significantly because of fuel-switching if Texas were not included in the Final Rule. *See, e.g.*, Comment submitted by Mark R. Vickery, Executive Director, Tex. Comm'n on Envtl. Quality, Document No. EPA-HQ-OAR-2009-0491-2857 (posted Oct. 7, 2010) (commenting on the Proposed Rule); *see also* Luminant PFR at 12-14.

Again, this problem was unique to Texas; no other State covered by the Final Rule was denied proposed budgets.

The absence of emissions budgets for Texas frustrated the purpose of the notice requirement. Without a proposed budget, Texas did not have, and could not have had, an opportunity to comment on a part of the rule that directly affects its interests. The budgets are the key limitation that the rule imposes, and as such are integral to the purported purpose of prohibiting interstate transport of regulated pollutants. Because it had no opportunity to examine the budgets that eventually appeared for the first time in the Final Rule, Texas was unable to adequately comment on the potential effects of the Final Rule on the State.

The lack of emissions budgets for Texas in the Proposed Rule was particularly problematic because it deprived the State of any opportunity to comment on the cost-benefit analysis that determines if a State should be included in a rule of this nature. Proposed Rule, 75 Fed. Reg. at 45,270-285. The central question of what costs EGUs would actually have to incur to meet EPA's budgets could not be answered without knowing what the budgets were. And the lack of that information caused specific harm because EPA's own cost-benefit analysis did not specifically evaluate Texas. Moreover, in the Final Rule, EPA made an erroneous determination that Texas EGUs could make the required emissions reductions at a cost of only \$500/ton of SO_2. *See* Final Rule, 76 Fed. Reg. at 48,251-252, 48,257-259.

That determination was based on several incorrect facts and analytical mistakes. For instance, in projecting power-industry compliance in 2012, EPA assumed (1) year-round operation of existing controls; (2) operation of scrubbers that are currently scheduled to come on-line by 2012; (3) some fuel-switching to lower-sulfur coal; and (4) changes in dispatch and generation shifting from higher-emitting units to lower-emitting units. *Id.* at 48,279-48,281. Had it received adequate notice of its inclusion for annual $PM_{2.5}$, Texas would have offered comment on these assumptions' specific inapplicability in Texas. *See* Elec. Reliability Council of Tex., Inc., Impacts of the Cross-State Air Pollution Rule on the ERCOT System, at 3-6 (Sept. 1, 2011) ("ERCOT Report," attached hereto as Ex. A and incorporated by reference herein); Luminant PFR at 27-35.

EPA's errors are significant, and its own analysis belies its assertion that Texas will be able to meet the Final Rule's budgets. EPA states that, for Texas and other "Group 2" States, *see* Final Rule, 76 Fed. Reg. at 48,214, the costs to meet the emissions budgets for SO_2 are capped at \$500/ton for 2012 and will remain constant. *Id.* at 48,251-252. But EPA also states that the costs necessary to meet budgets may escalate in 2014, given the emissions limits imposed upon "Group 1" states. EPA illustrates this in Table VI.B-3 of the Final Rule. *Id.* at 48,252 -253. This table shows that, to meet a budget of 243,000 tons of SO_2 emissions in 2014, Texas EGUs will have to expend \$10,000/ton. And because the \$10,000/ton figure is the highest cost level that EPA examined, this may well be an underestimate. Indeed, in light of EPA's numerous mistakes regarding Texas's ability to meet the budget it announced in the Final Rule, the \$10,000/ton figure is possibly a very large underestimation. Nevertheless, costs of \$10,000/ton to meet the SO_2 emissions limits in 2014 are unreasonable, and Texas should have been allowed a chance to explain why that was so during the notice-and-comment period.

EPA's own analysis also reveals the flaw in its prediction that Texas will be able to meet its 2013 emissions budget. Although EPA updated its lignite-usage information for Texas to reflect that fewer cost-effective emissions reductions would be available, *id.* at 48,284, it failed to account for this change in Texas's SO_2 budget. *Id.* at 48,269. Even if EPA maintains that this discrepancy does not interfere with Texas's ability to comply with the Final Rule because Texas's emissions would still fall below Texas's assurance level (287,866 tons for 2012, 2013, 2014 and beyond, *id.* at 48,269), that conclusion is flawed. A presumption that Texas must rely on allowances purchased from out-of-state sources in order to comply with the Final Rule improperly disregards rule-compliance costs and highlights the inadequacy of Texas's budget. Not only did EPA fail to consider the possibility that the required volume of allowances would be unavailable for purchase within the limited pool of Group 2 States, *see* ERCOT Report at 6, it also did not analyze this as a compliance option available at the $500/ton cost threshold. 76 Fed. Reg. at 48,279-281.[11]

Were Texas to have attempted its own analysis and guessed at a relationship between the control cost thresholds and a potential state budget, it could only have assumed that its SO_2 budget would have been set at around 293,000 to 295,000 tons. This would have been the only plausible assumption based on the EPA's data, which did not specify a cost threshold for Group 2 states, but rather indicated that some amount below $2000/ton was appropriate, with some States' budgets reflecting thresholds as low as $200/ton. Proposed Rule, 75 Fed. Reg. at 45,272, 45,281-282. The lack of a proposed cost-threshold for Texas EGUs would have further hampered any attempt by Texas to calculate a possible SO_2 budget. Operating on such inadequate information, a budget estimate at this level might have been approximately 50,000 tons higher than the SO_2 budget for Texas that was unveiled in the Final Rule.

The lack of a proposed SO_2 budget, combined with the lack of clarity regarding the appropriate cost threshold for Group 2 States and the incorrect base-case data, would have rendered any potential calculation by Texas regarding its SO_2 budget meaningless. Had the EPA provided a proposed budget to Texas, Texas would at least have had the same opportunities for budget review and comment that all other States covered by the Final Rule were provided. And that required notice

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11. *See also* Transport Rule Remedy Sensitivity Analysis: Cost-Effectiveness of Texas Emission Reductions, Environmental Protection Agency, Document No. EPA-HQ-OAR-2009-0491-4474 (posted July 12, 2011) (EPA emission projections considering revised lignite sensitivity analysis discussed in the Final Rule). If each of the States made exactly the reductions predicted by the EPA to be available to them at a $500/ton cost threshold (the threshold used by EPA for 2012 reductions), Texas's SO_2 emissions after those reductions (based on the lignite sensitivity) were 280,000 tons, and all available Group 2 allowances were sold *only* to Texas, Texas would still be short 23,894 allowances. Failure to hold 23,894 allowances to cover emissions (which are still within Texas's overall assurance limit) would result in a forfeiture by whichever EGUs were unable to secure those allowances from the following year's budget of 47,788 allowances. *See* 76 Fed. Reg. at 48,294-298. Further, were this 23,894-ton exceedance over available allowances to occur, it could result in civil penalties of up to $327,049,125,000 for just one control period (23,894 tons x 365 days in a control period x $37,500) and the potential for criminal penalties as well. *See* 42 U.S.C. § 7413(a)(3).

would have allowed Texas to assess possible emissions reductions and their anticipated ripple effects, such as impacts on electric reliability. *See infra* Part IV. As it stands, EPA has failed to acknowledge or account for the negative impacts of this rule on electrical generation in the State and the far-reaching effects it could have on Texas citizens. *Id.*

II. The Final Rule violates the CAA by setting emissions budgets for Texas that greatly exceed what would be required to eliminate Texas's purported significant contribution.

As another commenter has already noted, EPA's modeling reflects that Texas's alleged 0.18 $\mu g/m^3$ SO_2 contribution to downwind nonattainment for annual $PM_{2.5}$, *see* Final Rule, 76 Fed. Reg. at 48,240 (Table V.D-1), just barely exceeds the 0.15 $\mu g/m^3$ significance threshold, *id.* at 48,236, and is well below the alleged significant contributions of many other States. *See* Luminant PFR at 19-22 and Exhibit 7. Yet the Final Rule requires Texas to make the second largest reduction in 2012 SO_2 emissions. *See id.*; Final Rule, 76 Fed. Reg. at 48,269. This conspicuous disparity between Texas's alleged significant contribution and its required emissions reductions violates the CAA.

As the D.C. Circuit explained in *North Carolina*, EPA "is 'a creature of statute,' and has 'only those authorities conferred upon it by Congress'; 'if there is no statute conferring authority, a federal agency has none.'" 531 F.3d at 922 (quoting *Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001)). As already noted, the CAA gives EPA authority to require States to "prohibit[] . . . any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will . . . contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any . . . national primary or secondary ambient air quality standard." 42 U.S.C. § 7410(a)(2)(D)(i)(I). Neither this statutory provision nor any other, however, gives EPA authority to go further and require States to prohibit emissions below the significant-contribution threshold.

North Carolina speaks clearly on this point. There, the Court explained that, even though EPA's "redistributional instinct may be laudatory," section 7410(a)(2)(D)(i)(I) gives the agency "no authority to force an upwind state to share the burden of reducing other upwind states' emissions. Each state must eliminate its own significant contribution to downwind pollution. While [an EPA rule] should achieve something measurable towards that goal, it may not require some states to exceed the mark." 531 F.3d at 921. The Court confirmed that its previous decision in *Michigan* does not permit EPA to "just pick a cost for a region, and deem 'significant' any emissions that sources can eliminate more cheaply," explaining that "[s]uch an approach would not necessarily achieve something measurable toward the goal of prohibiting sources 'within the State' from contributing significantly to downwind nonattainment." *Id.* at 918 (quoting 42 U.S.C. § 7410(a)(2)(D)(i)(I)); *see also id.* at 919-20 (explaining that EPA "may not trespass beyond the bounds of its statutory authority by taking other factors into account than those to which Congress limited it, nor substitute new goals in place of the statutory objectives without explaining how doing so comports with the statute" (internal quotation marks and brackets omitted)).

As with the other matters addressed in Part I, Texas had no opportunity to comment on the severe disconnect between its minimal alleged downwind contribution at the Granite City monitor and the significantly disproportionate amount of emissions reductions the Final Rule requires of it. As already noted, EPA's modeling reflected that Texas did not significantly affect any monitor for purposes of the $PM_{2.5}$ NAAQS. But EPA significantly revised the modeling after issuance of the Proposed Rule, ultimately determining, in the Final Rule, that emissions from Texas exceeded the significance threshold. Final Rule, 76 Fed. Reg. at 48,240, 48242. The amount of that alleged overage, however, was minimal—a mere 1.05% of the 24-hour $PM_{2.5}$ standard and 1.2% of the annual $PM_{2.5}$ NAAQS standard. Yet the Final Rule requires a reduction of over 40% of Texas's total SO_2 emissions (as evidenced by Texas's emissions budget, which is more than 40% less than Texas's 2012 base case emission inventory for SO_2). *Id.* at 48305, 48269.

EPA has offered no explanation for this disparity, and it is difficult to see how any explanation could comport with *North Carolina*. EPA's only rationalization for the Final Rule's amount of reductions in Texas is based on cost-effectiveness. *Id.* at 48,246-264. But the D.C. Circuit has specifically foreclosed reliance on that rationale in this type of scenario. *North Carolina*, 531 F.3d at 918-21.[12]

Even if Texas could have reasonably guessed at a possible emissions budget, it could not have commented on the lack of a rational connection between the required emissions reductions and its purported significant contribution identified in the Final Rule because, as already noted, the Proposed Rule did not significantly link Texas to any downwind receptor monitors. And it would have been odd indeed for Texas to expect a significant-contribution linkage to the Granite City monitor, given that this monitor is currently monitoring $PM_{2.5}$ attainment. *See* Approval and Promulgation of Air Quality Implementation Plans; Illinois; Missouri; Saint Louis Nonattainment Area; Determination of Attainment of the 1997 Annual Fine Particulate Standard, 76 Fed. Reg. at 29,652 (May 23, 2011). It is difficult to see how EPA could rationally require *any* reductions based on data from a monitor showing attainment, much less reductions of over 40% of Texas's total SO_2 emissions.

III. The EPA should grant an administrative stay pending appellate review that postpones the Final Rule's effective date and compliance deadlines as they pertain to Texas.

Texas requests a partial administrative stay, postponing the Final Rule's effective date and compliance deadlines as they pertain to Texas and EGUs within the State. This stay would operate for a three-month period during agency reconsideration of the Final Rule, and/or for the entire period in which there is a pending application for judicial review, whichever is longer.

Authority for granting a stay derives from both the CAA, 42 U.S.C. § 7607(d)(7)(B), and the APA, 5 U.S.C. § 705. Under either provision, EPA has broad discretion to delay the effective date

12. Moreover, EPA's cost-effectiveness analysis is flawed in several respects, *see supra* Part I.B.4, and EPA has not identified a scientific basis for a specific amount of reductions that would correspond to Texas's purported significant contribution to nonattainment at the Granite City monitor.

of a rule, based on the specific facts and circumstances before it. *Cf., e.g.*, Industrial, Commercial, and Institutional Boilers and Process Heaters and Commercial and Industrial Solid Waste Incineration Units, 76 Fed. Reg. 28,662, 28,663 (May 18, 2011). Section 7607(d)(7)(B) authorizes EPA to postpone a rule's effectiveness for three months if a reconsideration proceeding is convened. It is apparent that EPA considers the three-month limitation to apply only to the agency's plenary authority to grant a stay without notice and comment. *See* Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Aggregation, 74 Fed. Reg. 22,693, 22,694 (May 14, 2009).

APA section 705 authorizes EPA to postpone the effectiveness of a rule pending judicial review when justice so requires. *See* 5 U.S.C. § 705. Section 705's general provisions applicable to federal agencies are not subject to the CAA's more specific provision applicable to the EPA. *See* 42 U.S.C. § 7607(d)(1) (stating that CAA section 7607(d) replaces sections 553-557 of the APA (except as otherwise provided in section 7607(d)), but not stating that it replaces APA section 705). Moreover, when needed, the EPA has used APA section 705 to continue the effect of a stay initially issued under CAA section 7607(d)(7)(B). *Cf.* NESHAP Radionuclide, 55 Fed. Reg. 10,455, 10,456 (Mar. 21, 1990).

A. Texas is entitled to a stay under CAA section 7607(d)(7)(B).

Beyond the requirement that a reconsideration proceeding be convened, CAA section 7607(d)(7)(B) imposes no other requirement for granting a three-month stay pending reconsideration. *Cf., e.g.*, National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants, 76 Fed. Reg. 28,318, 28,326 (May 17, 2011) (stating that stay was not appropriate under section 7607(d)(7)(B) because petitions for reconsideration were denied). No particular test or standard for evaluating a stay request is given. Nevertheless, past requests for stay submitted to the EPA reveal several considerations that may be taken into account in ruling on a stay request.

The EPA has considered whether a stay will provide sufficient time to reconsider an agency action or rule. *See, e.g.*, National Emission Standards for Hazardous Air Pollutants for Source Categories: Gasoline Distribution (Stage 1), 60 Fed. Reg. 62,991, 62,991 (Dec. 8, 1995). The EPA has also considered whether a stay will prevent "undue hardship" and "possible harm" to the requestor during reconsideration. *See, e.g.*, Standards of Performance for Petroleum Refineries, 73 Fed. Reg. 55,751, 55,752 (Sept. 26, 2008). Other considerations include: (1) "potential negative effects" on an industry, *see* National Emission Standards for Hazardous Air Pollutants, 56 Fed. Reg. 10,523, 10,523 (Mar. 13, 1991); (2) adverse economic consequences to the requestor such as substantial costs and business disruption, *see* Protection of Stratospheric Ozone, 60 Fed. Reg. 24,676, 24,678 (May 9, 1995); National Emissions Standards for Hazardous Air Pollutants, 57 Fed. Reg. 56,877, 56,878 (Dec. 1, 1992); and (3) potential environmental impacts, *see* Protection of Stratospheric Ozone, 60 Fed. Reg. 24,676, 24,678 (May 9, 1995).

Assuming Texas's request for reconsideration is granted, the facts and circumstances pertaining to Texas and Texas EGUs warrant at least a temporary stay of three months under CAA section 7607(d)(7)(B). To begin, given that the Final Rule's provisions applicable to Texas were first introduced in the Final Rule, represented a significant change from the Proposed Rule, and Texas had no opportunity to comment on these new requirements in the Final Rule, reconsideration will likely take considerable time and not conclude before the Final Rule's scheduled effective date.

Without a stay in place during reconsideration, Texas and its EGUs will experience significant harms. For one thing, without a stay, Texas EGUs will be required to take costly steps in order to attain compliance before reconsideration is likely concluded. These compliance efforts will require major investment by Texas EGUs, which may not be recoverable if reconsideration leads to significant revisions or abrogation of the rule as to Texas. *See* Luminant PFR at 33-36. Such unrecoverable costs could lead to dire economic consequences for Texas EGUs. Besides EGUs, the State of Texas and its citizens would also experience avoidable economic hardship. Absent a stay, if the Final Rule forces "EGUs in Texas . . . to cut production or shutdown in a matter of months," Texas can expect a potential "loss of jobs, loss of tax revenue, and collateral economic consequences, all of which will damage the small, rural communities that rely almost exclusively on . . . mines and plants for their economic livelihood." *Id.* at 34.

Making matters worse, without a stay, the Electric Reliability Council of Texas ("ERCOT") forecasts that the Final Rule's requirements applicable to Texas and the Final Rule's truncated implementation deadlines will have a profound negative impact on Texas EGU operations, which will, in turn, cause foreseeable near- and long-term adverse impacts to the ERCOT-system grid in the form of rotating outages of customer load, *i.e.*, rolling blackouts. *See* ERCOT Report at 4-7. Rotating power outages and the attendant destablization of the power-delivery system to residential, industrial, and commercial users has the potential to severely disrupt the Texas economy and inflict human suffering throughout the State.

All of these harms far outweigh the minuscule effect that the fine particulate-matter emanating from Texas currently has on air quality in other States. As already noted, the Final Rule's Texas provisions were imposed based solely on predicted emissions that Texas EGUs will contribute to nonattainment of the annual and daily $PM_{2.5}$ NAAQS in 2012 at a single monitor in Madison County, Illinois (the Granite City monitor), which already shows air-quality attainment. Final Rule, 76 Fed. Reg. 48,208, 48,223 (Aug. 8, 2011). The amount attributed to Texas currently is only 0.03 $\mu g/m^3$ above the significance level of 0.15 $\mu g/m^3$. *Id.* at 48,240. Issuing a temporary stay of the Texas provisions at this time will not cause any significant adverse environmental impacts or harm to the public at large. It will also not threaten the ability of the Granite City monitor to attain and maintain the annual $PM_{2.5}$ NAAQS, given that the monitor is, as already noted, in attainment status.

Weighing all of these factors, a stay under CAA section 7607(d)(7)(B) to preserve the status quo during EPA reconsideration of the Final Rule, as to Texas and EGUs within the State, is well justified.

B. Texas is entitled to a stay under APA section 705.

As already mentioned, APA section 705 grants the EPA authority to stay an agency order or final determination pending judicial review of such order or determination if the EPA finds "that justice so requires." 5 U.S.C. § 705. Section 705 also provides that a reviewing court may grant a stay pending appeal "to the extent necessary to prevent irreparable harm." *Id.* Beyond these requirements, section 705 specifies no further criteria to guide agencies in determining whether to grant a stay of an agency decision pending appeal.

At least one federal agency has looked to the Federal Rules of Appellate Procedure for additional guidance regarding the criteria that courts and agencies should use in determining whether to impose a stay of an agency decision. The Federal Election Commission has observed that Federal Rule of Appellate Procedure 18 permits a person to apply to the court of appeals in which a petition for direct review of an agency order or decision is pending for a stay of that order or decision. *See* Compliance Procedures, 50 Fed. Reg. 21,077, 21,079 (May 22, 1985). Rule 18, however, requires that, in most instances, application for a stay first be made to the administrative agency, as provided by 5 U.S.C. § 705. 50 Fed. Reg. at 21,079. In addition, FEC has noted that the advisory committee notes to Rule 18 state that the rule "merely assimilates the procedure for obtaining stays in agency proceedings with that for obtaining stays in appeals from the district courts." 50 Fed. Reg. at 21,079. Thus, according to the FEC, because an administrative agency is analogous to a district court in the situation where a stay is sought pending appellate review, the standard applied by the district courts in determining, in the first instance, if such a stay should be granted should likewise be applied by the administrative agency when confronted with the same issue. *Id.*

That standard is the familiar four-part test applied by federal courts in determining whether a stay or any other type of injunctive relief ought to be imposed pending a judicial action. Under that test, the petitioner must show that: (1) he or she will suffer irreparable injury in the absence of such a stay; and, if so, that (2) he or she has made a strong showing of the likelihood of success on the merits of the judicial action; (3) that such relief is consistent with the public interest; and (4) that no other party's interests will be substantially harmed by the stay. *Id.* (citing *Wash. Metro. Area Transit v. Holiday Tours, Inc.*, 559 F.2d 841, 842-43 (D.C. Cir. 1977); *Va. Petrol. Jobbers Ass'n v. Fed. Power Comm'n*, 259 F.2d 921, 925 (D.C. Cir. 1958)); *accord Special Counsel v. Campbell*, 58 M.S.P.B. 455, 457 (1993) (stating that whether a stay should issue under 5 U.S.C. § 705 depends on analysis under four-part test).

The Federal Energy Regulatory Commission takes a somewhat similar approach to that of FEC. FERC focuses on only two factors in determining whether to grant a stay pending appeal under APA section 705. Ceiling Prices; Old Gas Pricing Structure, 51 Fed. Reg. 27,529, 27,530 (Aug. 1, 1986); Regulation of Natural Gas Pipelines After Partial Decontrol, 50 Fed. Reg. 49,370, 49,370-71 (Dec. 2, 1985). FERC asks whether (1) implementation of the regulations will cause imminent, irreparable harm to the petitioner, and (2) staying the effectiveness of a regulation is in the public interest. 51 Fed. Reg. at 27,530; 50 Fed. Reg. at 49,370-71.

By contrast, EPA has shunned any test beyond simply section 705's "as justice so requires" standard. *See* EPA's Memorandum in Opposition to Sierra' Club's Motion for Summary Judgment and in Support of EPA's Cross-Motion for Summary Judgment 13-14, *in* No. 1:11-cv-01278-PLF, *Sierra Club v. Jackson* (Document 20, filed Aug. 25, 2011). EPA apparently believes that applying additional factors besides the "as justice so requires" standard is contrary "to the very language of the statute":

> Section 705 specifically provides a different standard: an agency may postpone the effective date of an agency action "when an agency finds that justice so requires." That Congress chose, in the second sentence of section 705, to make irreparable injury a predicate for a court's grant – presumably over an agency's objection – of a judicial stay in fact indicates that neither irreparable injury nor any other portion of the traditional judicial standard for granting preliminary relief is a predicate to an agency's own exercise of discretion under section 705: A reviewing court may postpone the effective date of agency action "only to the extent necessary to prevent irreparable injury": while an agency may do so when the agency finds that "justice so requires." By using different language, Congress established that the standards governing stays to be issued by the agencies and the courts are different. Further, the D.C. Circuit has articulated the standard for an agency's exercise of its authority under section 705 consistent with the text of the statutory provision, without referencing the factors [from the four-part test].

Id. at 13-14 (citing *Recording Indus. Ass'n of Am. v. Copyright Royalty Tribunal*, 662 F.2d 1, 14 (D.C. Cir. 1981)). Indeed, EPA has expressly disclaimed the four-part test in considering a request for stay pending appeal. *Id.* at 13 n.9. And EPA considers that its decision whether to stay the effective date of a Final Rule pending appeal need only be reasonable in light of the circumstances presented by the stay request. *See id.* at 14-15.

Thus, in determining a stay request pending appeal, EPA's sole focus has been section 705's "as justice so requires" standard. *Id.* at 14. Despite the inherently subjective nature of this inquiry, EPA has indicated that a stay may be appropriate when (1) an insufficient opportunity for public comment was given on certain revisions that EPA made to proposed rules, (2) data was received before rules were finalized that the EPA was unable to incorporate into the final rules, and (3) many facilities across multiple diverse industries might need to begin making major compliance investments in light of impending compliance deadlines, and those investments may not be reversible if the standards are in fact revised following reconsideration and full evaluation of all relevant data. *Id.* at 14. These elements—as well as the more stringent judicial-stay requirements noted above—are satisfied here.

1. Justice requires that the EPA grant Texas's stay request.

In light of the EPA's stated position on section 705 stays, Texas's requested stay should be granted for the following reasons. First, as explained above, Texas was not afforded adequate notice or a meaningful opportunity to comment on the Final Rule, and the lack of adequate notice prevented Texas from providing comments that would have significantly changed the Final Rule. *See supra* Part I.

Even more, the Final Rule will require Texas EGUs to make major compliance investments in light of the rule's impending deadlines. Five months to make the changes required by this rule is *per se* unreasonable, and EPA has provided no analysis or rational reason for how or why these reductions are to be made within the short time frame provided for compliance. These investments may not be reversible if the rule is in fact revised after reconsidering and fully evaluating all of the relevant data. *See* Luminant PFR at 33. As stated above, such unrecoverable costs could lead to dire economic consequences for Texas EGUs and have equally dire collateral economic consequences on Texas communities and the citizenry who rely on the EGUs for their economic livelihood. *See id.* at 33-34.

Taking into account all of those considerations, the equities weigh heavily in favor of granting Texas a stay pending judicial review. Nothing more should be required to grant Texas's stay request. If, however, the EPA needs further proof, consideration should be given to the irreparable harm that Texas and the public will suffer if a limited stay is not granted. In particular, if a stay pending appeal is not issued, the Final Rule, as it presently stands, will degrade Texas's electric reliability and threaten its electricity consumers with enhanced risk of power outages.

2. The Final Rule will cause irreparable harm to Texas.

The Final Rule threatens to disrupt the provision of reliable electricity through the interconnected web of electric-transmission systems serving Texas consumers. There are three main interconnected networks, or power grids, that comprise the electric-power system in the continental United States: the Eastern Interconnect, the Western Interconnect, and the Texas (ERCOT) Interconnect. The Texas Interconnect is not connected with the other networks, except through certain direct current ("DC") interconnection facilities, and the other two have limited interconnection with each other (also through DC interconnections). *See* Electric Power Industry Overview 2007, Energy Information Administration, *available at* http://www.eia.gov/cneaf/electricity/page/prim2/toc2.html.

Portions of Texas fall into each of the three interconnects, and power generation in Texas is monitored by several regional reliability councils, including ERCOT, the Western Electricity Coordinating Council ("WECC"), the Southwest Power Pool ("SPP"), and the Southeastern Electric Reliability Council ("SERC"). *See id.* The Final Rule could have direct impacts in all of the electric-power systems regulated by these regional reliability councils, including ERCOT. Because of their interconnectedness, compliance decisions made by one regional authority could impact the others. For example, compliance decisions made by Texas EGUs could have direct impacts to power-system reliability in the WECC, SPP, or SERC for EGUs whose operations span multiple States. These considerations are critical to understanding the far-reaching impact of the Final Rule. But notably, EPA did not evaluate these issues, nor did it provide an opportunity to comment on these impacts in the Proposed Rule. *See* Southwestern Public Service Company's Petition for Reconsideration, Docket No. EPA-HQ-OAR-2009-0491 (Aug. 23, 2011).

At the request of Texas's Public Utility Commission, however, ERCOT has at least studied the impact that the Final Rule will have on the reliability of Texas's primary electric grid and power-delivery system. *See generally* ERCOT report. The ERCOT Report demonstrates the harm to Texas. It concludes that the Final Rule will immediately and directly impact Texas EGUs through allocation of emission allowances, compliance deadlines, and substantial noncompliance penalties. *See id.* at 2-3. To achieve the impending compliance deadlines, EGUs must consider whether to implement one or more of several compliance options. *See id.* at 3-4.

One option for reducing SO_2 emissions is switching to "lower sulfur content fuel." *Id.* at 3. That switch, however, is fraught with risk. For one thing, "the demand for lower sulfur coal is expected to exceed the mining capacity and/or railroad capacity necessary to deliver the coal to Texas." *Id.* For another thing, the switch may cause "unit capacity derates" and "may require modifications to the unit's air emissions permit." *Id.* In any event, EPA provides no analysis of economic availability of low-sulfur coal. *See* Final Rule, 76 Fed. Reg. at 48,279-281.

Another option would involve more frequent use of existing SO_2 control equipment such as wet-limestone scrubbers and possibly increase the effectiveness of this equipment. *Id.* But this option is available to only "a small subset of coal plants in ERCOT" and, in any event, the expected benefit of employing this option is only a 1 to 2 percent decrease in the maximum net output of units to which the option might apply. *Id.* Additionally, increased use of such controls could easily require permit modifications that could not be completed in time to comply with the Final Rule's deadline, and EPA failed to consider SIP-approved state-specific permitting requirements.

A third option to reduce SO_2 emissions is dry sorbent injection. *Id.* This option may decrease SO_2 emissions by 25 to 30 percent in units without existing necessary control equipment. *Id.* But if this option is to be employed, public notice or modifications to air permits may be required. *Id.*

Reducing NO_X emissions will likely entail "high capital cost unit retrofits, including the addition of selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR) technologies." *Id.* Making these changes will require "several years for permitting, design and construction." *Id.* Given this reality, the Final Rule's near-term compliance deadlines are problematic, to say the least.

The near-term impossibility of these "options" leaves Texas EGUs with just one option: decrease production. This could be accomplished by (1) decreasing EGU outputs to their minimum levels during off-peak hours, then powering up to maximum capacity during peak afternoon hours; or (2) imposing extended unit outages. *Id.* Making either of these choices, however, will cause reliability problems. *See id.* at 3-4 (noting that, if these dispatch patterns are employed, traditionally base-loaded units can be expected to experience increased maintenance outages and long start-up requirements, making them unavailable during off-peak extreme weather events).

Considering these compliance options, ERCOT has estimated the likely "aggregate impacts on the ERCOT system." *Id.* at 4. ERCOT's analysis indicates that the Final Rule's "annual SO_2 program is likely to be the most restrictive on the ERCOT system." *Id.* The NO_X program is not as likely to be as restrictive as the SO_2 program, but, if Texas has another extended hot summer like the record one currently being experienced in 2011, EGUs would need to obtain additional emission allowances through trading of NO_X emissions allowances. *See id.*

However, "there will not be a liquid market throughout the year for allowances" due to uncertainty among resource owners and stiff civil and criminal penalties for non-compliance. *Id.* at 6. Moreover, it can be expected that unforeseen complications will likely cause the various compliance options to not always function as designed, nor perform as anticipated. *Id.* Given these assumptions, ERCOT developed three likely compliance scenarios to assess the risks to the system posed by the Final Rule. *Id.* All of the events depicted in these scenarios are reasonably foreseeable in light of the realities of having to comply with the Final Rule.

Scenario one relies on the compliance plans of which Texas EGUs have notified ERCOT. *Id.* This scenario anticipates an incremental reduction in available operating capacity of approximately 3,000 MW in the off-peak months of March, April, October, and November, and an operating capacity reduction of 1,200-1,400 MW during the remainder of the year, including the peak-load months of June-August. *Id.*

Scenario two builds upon the first by assuming that increased dispatching of "base-load units" will cause increased maintenance outages, especially in the fall months. *Id* at 5. That is, beyond the reduced capacities assumed in scenario one, the outages envisioned under scenario two will result in an additional loss of approximately 5,000 MW of capacity during October and November, and possibly December. *Id.*

Finally, scenario three adds to scenario two by considering "possible near-term market limitations on the availability of imported low-sulfur coals, either due to nationwide demand exceeding mine output capacity or railroad shipping capacity." *Id.* This occurrence would unleash a domino effect whereby "coal plant resource owners would be forced to rely on higher sulfur coals during the spring and peak season summer months," and then, in order to conserve allocated resources, these owners would be forced to reduce unit output in the fall, causing decreased capacity in October and November. *Id.* As a result, under scenario three's assumptions, the ERCOT system could experience approximately 6,000 MW of lost capacity during October and November, and possibly December, which would be in addition to the reduced capacities of scenario one. *Id.* That is, scenario three could result in 1,000 MW more in lost capacity during October, November and December beyond that which is envisioned under scenario two. *Id.* Additionally, in this third scenario, ERCOT would expect incremental capacity losses of approximately 3,000 MW in the off-peak months of March and April and approximately 1,200-1,400 MW during the remainder of the first nine months of the year. *Id.*[13]

Even under the best-case scenario (scenario one), ERCOT can expect that EGUs' attempts at complying with the Final Rule will result in "a reduction in available operating capacity of 1,200-1,400 MW during the peak season of 2012." *Id.* To put that operating loss into perspective, if it had occurred in the peak season of 2011, ERCOT would have experienced rotating outages in August. *Id.* Even without the Final Rule that would force ERCOT to lose thousands of MWs of generation capacity, on at least one day this summer, ERCOT was forced to import over 1,000 MW under emergency protocols from grids outside ERCOT to meet its system needs. *See* Press Release, Elec. Reliability Council of Texas, ERCOT Breaks Peak Demand Record Third Time (August 3, 2011), *available at*, http://www.ercot.com/news/press_releases/show/416. It is therefore easily foreseable that implementation of the Final Rule has a significant likelihood of resulting in rolling blackouts in 2012 and beyond.

What is more, there is a greater risk of rotating outages during the off-peak months, too, because of the reductions predicted in the three scenarios coupled with annual maintenance outages and weather variability during the off-peak season. ERCOT Report at 5. As undesirable as these scenarios are, they likely *underestimate* the severity that might befall Texas if the Final Rule goes into effect. Open Meeting of the Pub. Util. Comm'n of Tex., Hearing on the Reliability Impacts of CSAPR, Sept. 1, 2011 (statement of Warren Lasher, ERCOT System Planning Manager (minutes 30:20-31:13), *available at* http://www.texasadmin.com/puct.shtml)); *see also* ERCOT Report at 6 (explaining that, "[d]ue to numerous uncertainties, ERCOT cannot confidently estimate a 'worst case' scenario at this time"). Combinations of certain events discussed in the ERCOT Report may "further increase the risk of increasingly frequent and unpredictable emergency conditions, including the potential for rotating outages." ERCOT Report at 6. In sum, the Final Rule's effective date and compliance deadlines do not allow ERCOT and Texas EGUs sufficient time to take the steps necessary to avoid the loss of thousands of megawatts of capacity and the specter of rotating outages for Texas power customers. *See id.* at 7.

As it presently stands, the Final Rule threatens to destabilize Texas's power-delivery system by increasing the risk of rotating power outages that will leave swaths of Texans without electricity for indeterminate periods of time. That situation is *per se* irreparable harm. *See Cal. Indep. Sys. Operator Corp. v. Reliant Energy Servs., Inc.*, 181 F. Supp. 2d 1111, 1121 (E.D. Cal. 2001) (holding that rolling blackouts put health and safety of citizens at risk and constitute irreparable harm); *see also Westlands Water Dist. v. U.S. Dep't of Interior*, No. Civ. F00-7124 WWDLB, 2001 WL 34094077, at *11 n.33 (E.D. Cal. 2001) (stating that serious harm occurs when energy cannot be obtained and power consumers are directly deprived); *U.S. Transmission Sys. v. Americus Ctr., Inc.*, Civ. A. No. 85-7044, 1986 WL 1202, at *12 (E.D. Pa. 1986) (stating that the termination of essential utilities such as electricity can cause irreparable harm). Indeed, the mere "threat of a blackout"

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13. All of these scenarios fail to consider: (1) possible barriers to increasing production (at units that are currently designated as "peaking units") that are inherent in modification of existing permits; and (2) the necessity of meeting other federal standards, including both the 2010 NO_X and SO_2 NAAQS.

demonstrates irreparable harm. *Cf. City of Cleveland v. Cleveland Elec. Illuminating Co.*, 684 N.E.2d 343, 350 (Ohio Ct. App. 1996); *cf. also Pa. Power & Light Co. v. Leininger*, No. 81 E 30, 1983 WL 384, at **5 (Pa. Ct. Common Pleas 1983) (holding that defendant's actions constituted a clear and present as well as future danger of irreparable harm to an electrical company's customers by hindering or obstructing the company's maintenance of a power transmission line serving those customers).

Should rotating outages occur, Texas can expect severe economic and concomitant public-health effects, including death or severe disablement.[14] The effects would be most pronounced during summer and winter, when Texas experiences both extreme heat and cold events. *See generally* http://atmo.tamu.edu/osc/ (information available from the Office of the Texas State Climatologist). The Final Rule's adverse consequences will result in substantial risks to the health, welfare, and lives of Texans—vulnerable senior citizens and economically disadvantaged families in particular. Heat is the number one weather-related killer in the United States, resulting in hundreds of fatalities each year. On average, excessive heat claims more lives each year than floods, lightning, tornadoes, and hurricanes combined. *See* Heat Wave: A Major Summer Killer, Nat'l Oceanic & Atmospheric Admin., *available at* http://www.noaawatch.gov/themes/heat.php. An average of approximately 175 people die each year from heat-related causes. *See* The Heatwave of July 1995, Nat'l Oceanic & Atmospheric Admin., *available at* http://www.crh.noaa.gov/arx/events/heatwave95.php. Heat waves can exacerbate heat-related deaths, as illustrated during the summer of 1980 when an estimated 10,000 people were killed nationwide by a heat wave. *See* Billion Dollar U.S. Weather Climate Disasters, Nat'l Oceanic & Atmospheric Admin., *available at* http://lwf.ncdc.noaa.gov/oa/reports/billionz.html. In August 2003, an estimated 50,000 Europeans were killed by a heat wave. *See* Heat Wave: A Major Summer Killer, Nat'l Oceanic & Atmospheric Admin., *available at* http://www.noaawatch.gov/themes/heat.php.

According to EPA, "[a]ir conditioning is the best defense" to prevent heat-related problems, and EPA therefore recommends that local governments "work with utilities to ensure that no one's electricity is turned off during a heat wave." *See* Planning for Excessive Heat Events, EPA (Apr. 2009), *available at* http://www.epa.gov/agingepa/resources/factsheets/lowlit_itdhpfehe_100-F-09-019.pdf. As a result of power shortages due to Japan's recent earthquake and tsunami, the number of people taken to the hospital for heatstroke tripled in June of this year, compared to June of last year. *See* Michael Marshall & Wendy Zuckerman, Japanese Power Cuts Linked to Heatstroke Deaths, NEW SCIENTIST, July 19, 2011, *available at* http://www.newscientist.com/article/dn20716-japanese-power-cuts-linked-to-heatstroke-deaths.html. Japanese health experts are warning the public of the risk of heat stroke if they refrain from using air conditioning, noting that "air conditioning is the best help for people with illnesses and for elderly people to avoid heatstroke."

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14. Mortality and morbidity associated with extreme temperature related events is widely discussed and acknowledged. Power outages due to inadequate base-load capacity will likely increase mortality and morbidity following implementation of the Final Rule during months in which extreme temperature events are likely.

See Heatstroke Feared as People Save Power, JAPAN TIMES ONLINE, July 10, 2011, *available at* http://search.japantimes. co.jp/cgi-bin/nn20110710a3.html.

Moreover, economic hardship will result from power-plant shutdowns and lignite-mine closures. Not only will the people currently employed by these plants suffer the harm of unemployment, but the entire area will also suffer economic depression. Tax revenue from the power industry and associated mining activity funds significant portions of county tax rolls. The education system and infrastructure of an area supported by this industry will not be sustainable without sufficient revenue. As an example of the potential economic harm, the Texas Comptroller estimates that a loss of just $1 million from power production in Titus County would result in an additional loss of $420,000 and three jobs within Texas. Within the county, the loss would amount to an additional $160,000 for each million dollars of direct loss of revenue. (For comparison purposes, the estimated appraised value of the power plant and mine in Titus County is $967 million. The amount of tax revenue to Titus County is $16.7 million. In addition, the mines for this plant also provide approximately $386,000 in tax revenue to two other counties, Camp and Hopkins Counties.)

That is not all. As electricity demand increases to a point that electric reliability in the ERCOT region is jeopardized, ERCOT will implement its Energy Emergency Alert procedures to prevent loss of power across the grid. To meet electricity demand under constrained system operations, ERCOT first seeks demand reduction through a program of voluntary load curtailment in an effort to avoid involuntary load shed (rolling blackouts). To the extent that constrained system operations lead customers (*i.e.*, hospitals, schools, water/waste water treatment plants) choose to utilize back-up generators, these units would emit at substantially higher emission rates than coal-fired EGUs, and they would have a direct impact on highly populated urban areas with existing air-quality challenges such as Dallas, Houston, Austin, and San Antonio. However, if after taking all of these steps, ERCOT cannot satisfy electricity demand with available generation resources, ERCOT's only remaining option would be to order involuntary load shed in the form of rotating blackouts.

In short, Texas has shown that the Final Rule presents a real and imminent threat to Texas's power-delivery system—which in turn threatens Texans' lives and livelihoods. For this additional reason, a stay should be granted pending judicial review of the Final Rule.

RELIEF REQUESTED

For the reasons explained above, Texas respectfully requests that EPA convene a proceeding for reconsideration of the Final Rule. Texas further requests an immediate stay of the Final Rule's effectiveness and its compliance deadlines as to Texas for the longer of EPA's reconsideration proceeding or any subsequent action for judicial review. Finally, Texas requests that EPA extend the compliance deadlines as to Texas to reflect any period during which the rule's effectiveness was stayed.

Respectfully submitted,

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EXHIBIT A

Impacts of the Cross-State Air Pollution Rule on the ERCOT System

EXHIBIT

A

September 1, 2011

Executive Summary

ERCOT was asked by the Public Utility Commission of Texas (PUCT) in the Open Meeting on July 8, 2011, to evaluate the impacts of the Cross-State Air Pollution Rule (CSAPR) on the reliability of the ERCOT grid. The ERCOT analysis included meetings with representatives of the Texas Commission on Environmental Quality and the U.S. Environmental Protection Agency, review of the compliance strategies provided by the owners of coal-fired resources in the ERCOT region, and consolidation of these compliance strategies for purposes of evaluating system-wide impacts.

Based on the information provided by the resource owners, ERCOT developed three scenarios of potential impacts from CSAPR. The first scenario, derived directly from the compliance plans of individual resource owners, indicates that ERCOT will experience a generation capacity reduction of approximately 3,000 MW during the off-peak months of March, April, October and November, and 1,200 – 1,400 MW during the other months of the year, including the peak load months of June, July and August. Scenario 2, which incorporates the potential for increased unit maintenance outages due to repeated daily dispatch of traditionally base-load coal units, results in a generation capacity reduction of approximately 3,000 MW during the off-peak months of March and April; 1,200 – 1,400 MW during the remainder of the first nine months of the year; and approximately 5,000 MW during the fall months of October, November and possibly into December. Scenario 3 includes the impacts noted for Scenario 2, along with potential impacts from limited availability of imported low-sulfur coal. This scenario results in a generation capacity reduction of approximately 3,000 MW during the off-peak months of March and April; 1,200 – 1,400 MW during the remainder of the first nine months of the year; and approximately 6,000 MW during the fall months of October, November and possibly into December.

When the CSAPR rule was announced in July, it included Texas in compliance programs that ERCOT and its resource owners had reasonably believed would not be applied to Texas. In addition, the rule required implementation within five months – by January 2012. The implementation timeline provides ERCOT an extremely truncated period in which to assess the reliability impacts of the rule, and no realistic opportunity to take steps that could even partially mitigate the substantial losses of available operating capacity described in the scenarios examined in this report. In short, the CSAPR implementation date does not provide ERCOT and its resource owners a meaningful window for taking steps to avoid the loss of thousands of megawatts of capacity, and the attendant risks of outages for Texas power users.

If the implementation deadline for CSAPR were significantly delayed, it would expand options for maintaining system reliability. ERCOT is advancing changes in market rules – such as increasing ERCOT's ability to control the number and timing of unit outages and expanding demand response – that could help avert emergency conditions. These measures will not, however, avoid the losses in capacity due to CSAPR that increase the risk of such emergencies. As discussed in this report, those losses will, at best, present significant operating challenges for ERCOT, both in meeting ever-increasing peak demand and in managing off-peak periods in 2012 and beyond.

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Impacts of the Cross-State Air Pollution Rule on the ERCOT System

1. Introduction

ERCOT was asked by the Public Utility Commission of Texas (PUCT) in the Open Meeting on July 8, 2011, to evaluate the impacts of the Cross-State Air Pollution Rule (CSAPR) on the reliability of the ERCOT grid. The final language of the CSAPR was released by the U.S. Environmental Protection Agency (EPA) on July 6, 2011, and was published in the Federal Register on August 8, 2011.

The CSAPR is one of several environmental rules proposed by EPA that affect electric generation. The CSAPR includes three separate compliance programs: an annual SO_2 program, an annual NO_X program, and a peak season NO_X program (for emissions during the peak ozone season of May – September). In the proposed rule (then known as the Clean Air Transport Rule [CATR]), Texas was only included in the peak season NO_X program. Based on the proposed rule, an ERCOT study completed on June 21, 2011, evaluating the expected impacts of the pending regulations, did not include any incremental impacts from the CATR on the ERCOT system.

In the CSAPR rule actually adopted by the EPA, however, Texas is included in all three compliance programs - the peak season NO_X program, the annual NO_X program, and the annual SO_2 program. The implementation date for the CSAPR is January 1, 2012.

In order to accomplish this review, ERCOT undertook several activities.

- ERCOT reviewed documentation published on the EPA web-site regarding the rule.
- ERCOT met with representatives of the Texas Commission on Environmental Quality (TCEQ) and the EPA.
- ERCOT consulted with environmental experts from several of the generating entities in the ERCOT region whose facilities were likely to be affected by the CSAPR regulations. The purpose of these meetings was to ascertain the likely compliance plans for those resources owners.
- These compliance plans were aggregated so that ERCOT could evaluate the likely impacts to grid reliability.

2. Rule Description

The CSAPR is being implemented in order to address the interstate transport of sulfur dioxide (SO_2) and nitrogen oxides (NO_X). The rule is a replacement for the Clean Air Interstate Rule (CAIR), which was implemented in 2005. The CAIR was remanded to the EPA by the United States Court of Appeals for the District of

Columbia Circuit in 2008. In the CAIR program, Texas was regulated for particulate matter emissions (annual NOX and SO2 emissions).

Under CSAPR, generating units in Texas will be regulated for annual emission of SO2 and NOX, as well as emissions of NOX during the peak season (May – September). Each unit will be given a set allocation of emissions allowances. At the end of the calendar year, resource owners must turn in one allowance for each ton of emissions or be subject to penalties. Intra-state trading of allowances between resource owners is unlimited in the rule. However, interstate trading of allowances is capped – no state can have annual net imports of allowances of more than approximately 18% of the total state allocation of allowances. If this limit is exceeded, any resource owner that contributed to the excessive use of imported allowances will be subject to penalties.

Resource owners in Texas are permitted to trade SO2 allowances with resource owners in Kansas, Nebraska, Minnesota, Alabama, Georgia and South Carolina. Trading of NOX emissions will be allowed with states as depicted on the following map.

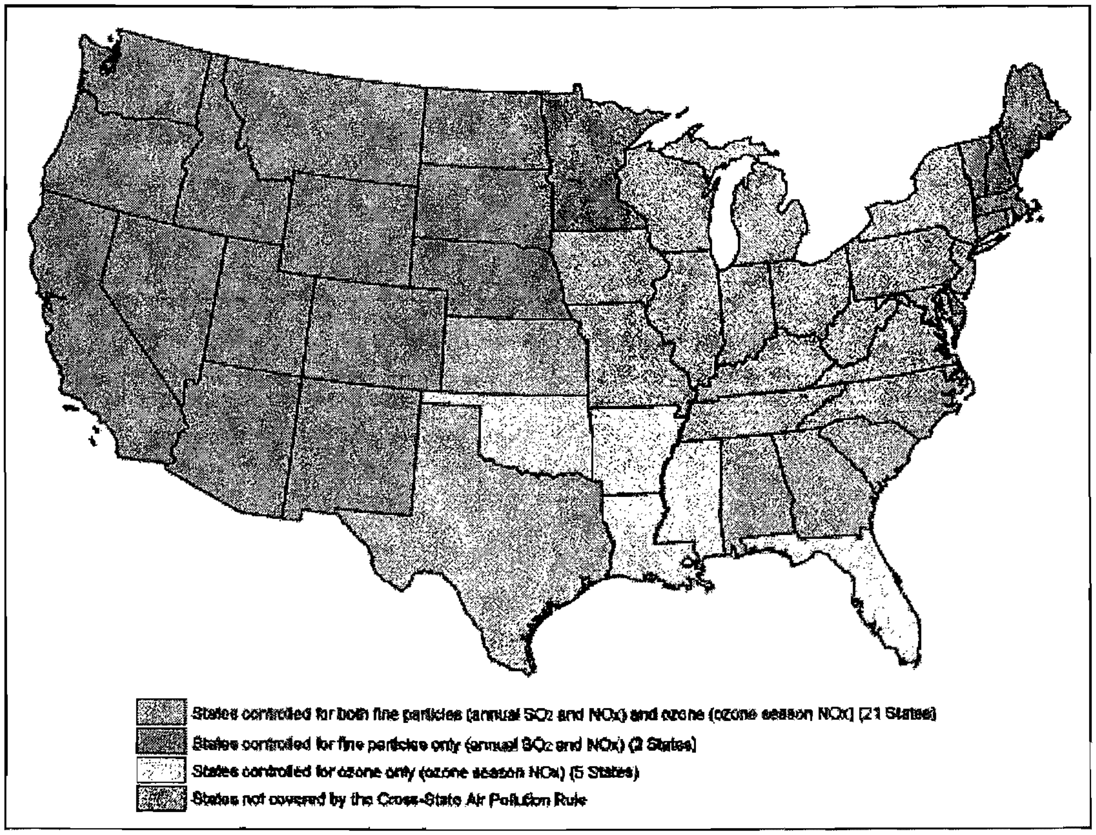

Figure 1: States Included in the Cross-State Air Pollution Rule

Resource owners who have emissions in excess of their annual allocations will have their next year's allocations reduced by one emission for each excess ton of emissions, plus a penalty of two additional allowances for each excess ton. In addition, the Clean Air Act includes provisions for civil lawsuits in the event of non-compliance. Non-compliance penalties under the CSAPR program are substantial, and can reach up to $37,500 per violation per day. In addition to program penalties, failure to comply can subject entities to the risk of civil penalties, lawsuits by private parties, and criminal liability.

3. Compliance Options

Resource owners have several near-term compliance options to meet the emissions limits established by the CSAPR. In order to reduce SO_2 emissions, lower sulfur content fuel can be used. In the case of plants that are currently burning lignite coal, or a mix of lignite and sub-bituminous coals (such as coal from the Powder River Basin [PRB] region of northwest Wyoming), increasing the use of low sulfur western coal will reduce SO_2 emissions. Units that currently are being fueled exclusively by western sub-bituminous coals can be switched in whole or in part to ultra-low-sulfur western coals.

In the near-term, the demand for lower sulfur coal is expected to exceed the mining capacity and/or the railroad capacity necessary to deliver the coal to Texas. In addition, the use of lower sulfur coals can result in unit capacity derates due to increased heat content of the fuel. Unit modifications to resolve any such derates may require modifications to the unit's air emissions permit.

Existing SO_2 control equipment, such as wet-limestone scrubbers, can be utilized more frequently than is current practice, and in some cases the effectiveness of this equipment can be increased. This option only applies to a small subset of coal plants in ERCOT, and the use of scrubbers results in a decrease in maximum net output from the affected units of about 1 to 2 percent.

The use of dry sorbent injection is another compliance option to reduce SO_2 emissions. Dry sorbent compounds, such as sodium bicarbonate and trona, can be injected into a flue duct where they react with SO_2 (and acid gases) to form compounds that can be removed using an electrostatic precipitator (ESP) or baghouse. Resource owners exploring this option anticipate that it will provide a 25 – 30% reduction in emissions of SO_2 on units without existing SO_2 control equipment. The use of dry sorbent injection may require public notice or air permit modification.

Most of the low cost options to reduce NO_X emissions have been utilized to comply with existing air quality regulations. Further reductions will likely require high capital cost unit retrofits, including the addition of selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR) technologies. Any such unit changes would require several years for permitting, design and construction.

The remaining option for reducing SO_2 and NO_X emissions will be reducing unit output, either through dispatching units down to minimum levels during the off-peak hours and up to maximum capacity during peak afternoon hours, or through extended unit outages. Some of the traditionally base-loaded units will experience increased maintenance outages due to this daily dispatch pattern. These same base-load units have long start-up requirements, which could make them unavailable for operation during some off-peak extreme weather events.

4. Study Methodology

In order to evaluate the potential impacts associated with implementation of the CSAPR, ERCOT met with representatives of the TCEQ and the EPA to evaluate details of the rule and its implementation. ERCOT also reviewed compliance strategies provided by the owners of coal-fired resources in the ERCOT region. ERCOT consolidated these compliance strategies for purposes of evaluating system-wide impacts.

5. CSAPR Impacts

The compliance strategies of individual resource owners were compiled and consolidated to determine the aggregate impacts on the ERCOT system. This analysis indicates that, of the three CSAPR programs, the annual SO_2 program is likely to be the most restrictive on the ERCOT system. Even though individual units may have emissions in excess of the peak season or annual NO_X limits, Texas as a whole is likely to be below the state-wide limit, indicating that resource owners can achieve compliance through trading of NO_X emissions allowances. An extended hot summer, such as the one experienced in 2011, may result in limited availability of peak season NOX emissions, and a need to obtain additional allowances from out-of-state.

In consolidating the compliance strategies from the resource owners, it became apparent that each resource owner was assuming a level of effectiveness of the various compliance options identified in Section 3. While many of these compliance plans are likely to be adequate, given the risks associated with each compliance option, it is unlikely that all of the resource owners' plans will function as designed. For example, the use of dry sorbent injection on the scale required to attain compliance at certain facilities may perform as anticipated, but its use in this context is novel and may involve unexpected complications. As a result, ERCOT has developed three compliance scenarios in order to assess the potential risks to the system based on different assumptions regarding implementation of compliance strategies.

The first scenario is derived directly from the compliance plans of individual resource owners. Based on the information that ERCOT has been given, in this scenario, the ERCOT region will experience an incremental reduction in available operating capacity of approximately 3,000 MW in the off-peak months of March, April, October and November, and an operating capacity reduction of 1,200 – 1,400 MW during the other months of the year, including the peak load months of June, July and August. Capacity reductions in the off-peak months are expected to be greater because power prices are lower during these periods, making them a more attractive time for resource owners to take extended outages to conserve allocated allowances.

The second scenario is derived from the first, but includes the additional assumption that the increased dispatching of base-load units will lead to increased maintenance outages, especially in the fall months. Over the course of the spring months it may become increasingly apparent that dispatching specific units is leading to extensive maintenance requirements. In these cases it may be cost-effective to idle these units rather than dispatch them down to minimum levels during off-peak hours. These units would likely be run through the summer peak months, but then would be idled for an extended period in the fall in order to conserve allocated allowances. Given this additional constraint, it is likely that ERCOT would experience an incremental loss of approximately 3,000 MW of capacity in the off-peak months of March and April, approximately 1,200 – 1,400 MW during the remainder of the first nine months of the year, and approximately 5,000 MW of capacity during the fall months of October, November and possibly into December.

The third scenario is derived from the second, with the added consideration of possible near-term market limitations on the availability of imported low-sulfur coals, either due to nationwide demand exceeding mine output capacity or railroad shipping capacity. In the event of such limitations, coal plant resource owners would be forced to rely on higher sulfur coals during the spring and the peak season summer months. As a result, they would be forced to further reduce unit output in the fall months, beyond what is currently included in their compliance strategy, and could be required to decommit additional capacity in October and November in order to conserve allocated allowances. As a result, given these assumptions, it is likely that ERCOT would experience an incremental loss of approximately 3,000 MW of capacity in the off-peak months of March and April, approximately 1,200 – 1,400 MW during the remainder of the first nine months of the year, and approximately 6,000 MW of capacity during the fall months of October, November and possibly into December.

6. Discussion

The scenarios analyzed in this study represent best-case (Scenario 1), and two cases with increasing impacts to system reliability. Scenarios 2 and 3 are based on the occurrence of events that are reasonably foreseeable given the circumstances facing generation resources attempting to comply with the CSAPR. Even in the best-case scenario, ERCOT is expected to experience a reduction in available operating capacity of 1,200 – 1,400 MW during the peak season of 2012 due to implementation of the CSAPR. Had this incremental reduction been in place in 2011, ERCOT would have experienced rotating outages during days in August. Off-peak capacity reductions in the three scenarios evaluated as part of this study, when coupled with the annual maintenance outages that must be taken on other generating units and typical weather variability during these periods, also place ERCOT at increasing risk of emergency events, including rotating outages of customer load.

There are numerous unresolved questions associated with the impacts of the CSAPR on the ERCOT system. It is important to note that the resource owners have had less than two months to develop compliance plans for the new rule. These plans are still preliminary and based on assumptions regarding technology effectiveness, fuel markets, impacts of altered unit operations on maintenance requirements, and the cost-effectiveness of modifying and operating units to comply with the CSPAR. The overall system impacts noted in this study will change if these individual compliance strategies are adjusted to take into account updated information.

The availability of SO_2 allowances for purchase by resource owners in Texas is a significant source of uncertainty at this time. A lack of allowances for purchase from out-of-state resources will likely increase the severity of the CSAPR rule. Many resource owners expressed their concern that parties that have excess allowances may, at least initially, hold on to their excess, in order to maintain flexibility and future compliance options. As noted in Section 2, given the penalties for non-compliance, resource owners are unlikely to exceed the number of allowances they have in hand, with the expectation that allowance markets will open up later in the year. It may be that some resource owners will keep their excess allowances until it becomes clear that they will not be needed, late in the year. Other resource owners may have to shut units down in the early fall in order to conserve allowances.

In addition, the information ERCOT has received indicates there will not be a liquid market throughout the year for allowances, which will make it difficult to determine the appropriate value of allowances to compensate resource owners for operations associated with reliability commitments, such as through the daily or hourly reliability unit commitment process. It may be necessary to administratively establish a value for these allowances through the market stakeholder review process.

It is also possible that the impacts of CSAPR will increase in 2013 and 2014. In those years, it is unlikely that resource owners will have any additional options for rule compliance. Increased dispatching of base-load units will likely continue to lead to extended maintenance outages, and delivered availability of low sulfur western coals is likely to remain limited. In addition to these factors, some resource owners will be placing units on extended outages to install emission control technologies, such as wet-limestone scrubbers and possibly selective catalytic or selective non-catalytic reduction equipment. These retrofit outages could further reduce the generation capacity available during off-peak months.

Due to the numerous uncertainties, ERCOT cannot confidently estimate a "worst case" scenario at this time. Combinations of particular events may result in reductions in operating capacity that exceed those identified in Scenario 3, and thus further increase the risk of increasingly frequent and unpredictable emergency conditions, including the potential for rotating outages. The best outcome ERCOT can expect occurs if Scenario 1 is realized (*i.e.,* all generation resources' current plans come to fruition), and, as discussed above, Scenario 1 appreciably increases risks for the ERCOT system, in both the on-peak and off-peak months.

7. Conclusion

When the CSAPR rule was announced in July, it included Texas in compliance programs that ERCOT and its resource owners had reasonably believed would not be applied to Texas. In addition, the rule required implementation within five months – by January 2012. The implementation timeline provides ERCOT an extremely truncated period in which to assess the reliability impacts of the rule, and no realistic opportunity to take steps that could even partially mitigate the substantial losses of available operating capacity described in the scenarios examined in this report. In short, the CSAPR implementation date does not provide ERCOT and its resource owners a meaningful window for taking steps to avoid the loss of thousands of megawatts of capacity, and the attendant risks of outages for Texas power users.

If the implementation deadline for CSAPR were significantly delayed, it would expand options for maintaining system reliability. ERCOT is advancing changes in market rules – such as increasing ERCOT's ability to control the number and timing of unit outages and expanding demand response – that could help avert emergency conditions. These measures will not, however, avoid the losses in capacity due to CSAPR that increase the risk of such emergencies. As discussed in this report, those losses will, at best, present significant operating challenges for ERCOT, both in meeting ever-increasing peak demand and in managing off-peak periods in 2012 and beyond.

Exhibit B

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August 5, 2011

VIA FEDERAL EXPRESS AND ELECTRONIC MAIL

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RE: Request for Partial Reconsideration and Stay of EPA's Final Rule titled "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States" signed July 6, 2011 (Docket No. EPA-HQ-OAR-2009-0491)

Dear Administrator Jackson and Assistant Administrator McCarthy:

Luminant[1] respectfully requests that the U.S. Environmental Protection Agency ("EPA") grant partial reconsideration and immediately stay the compliance deadline and effective date of EPA's Final Rule signed July 6, 2011, titled "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States" ("Final Transport Rule" or "FTR"[2]) as it applies to Texas.

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[1] This request is submitted by Luminant Generation Company LLC, Sandow Power Company LLC, Big Brown Power Company LLC, Oak Grove Management Company LLC, Luminant Mining Company LLC, Big Brown Lignite Company LLC, Luminant Big Brown Mining Company LLC, and Oak Grove Mining Company LLC—referred to here collectively as "Luminant."

[2] The pre-publication version of the Final Transport Rule, signed on July 6, 2011, is cited as "FTR."

Less than a year ago, EPA concluded that Texas emissions have no significant downwind effect on other states, and it issued a proposed rule that did not include Texas in the group of states required to address downwind effects related to fine particulate matter ("$PM_{2.5}$"). Without providing fair notice and opportunity to comment, EPA now mandates in the Final Transport Rule that Texas slash its SO_2 emissions by half and greatly reduce NOx emissions in less than five months—an unprecedented and unreasonable compliance timetable. Further, EPA would have Texas bear twenty-five percent of the SO_2 reduction burden imposed under this rule (more than twice the state's contribution to the total SO_2 emissions of all states included in the rule) and reduce NOx emissions beyond the sixty-two percent reduction achieved by the state between 1995 and 2010. These requirements will seriously jeopardize the ability of the state's electric grid to supply power to Texas businesses and consumers and threaten the loss of hundreds of high-paying rural jobs. EPA imposes these requirements based on its erroneous, highly speculative prediction that a tiny contribution from Texas to the air quality at a single monitor located nearly five hundred miles away in Illinois will cause that monitor to be in nonattainment with the EPA's $PM_{2.5}$ standards in 2012, ignoring EPA's own finding that this very site is already in air-quality attainment. EPA has issued this mandate without providing the state an opportunity to offer an implementation plan of its own, a failure that is beyond EPA's legal authority and is contrary to the fundamental structural component of the Clean Air Act—the statute's framework of "cooperative federalism."

As a matter of process and substance, the Final Transport Rule's mandates are unjust and unlawful and will cause irrevocable harm to Texas and to Luminant. For these reasons, the significant flaws underlying the Final Transport Rule's application to Texas warrant partial reconsideration and a stay of the compliance deadline and effective date of the rule as it applies to Texas.

Accordingly, Luminant requests that EPA convene a proceeding for reconsideration of the Final Transport Rule as it applies to Texas, including the annual emissions budgets for sulfur dioxide ("SO_2") and nitrogen oxides ("NOx"), the seasonal budget for NOx, and the compliance deadlines and obligations for both the annual and seasonal programs.[3] Luminant further requests that, as to Texas, EPA stay and delay the effective date of the rule and the compliance deadline

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[3] Luminant is requesting reconsideration and stay of the SO_2 and NOx annual budgets for Texas, the NOx seasonal budget for Texas, the FIPs that EPA is issuing for Texas, and the compliance deadlines and obligations for Texas EGUs under both the annual and seasonal programs. Although Texas was proposed to be included in the seasonal NOx program, the new seasonal budget finalized by EPA is significantly lower than the proposed budget (75,574 tons versus 63,043 tons) and suffers from many of the same underlying errors and assumptions as EPA's annual NOx budget for Texas, as discussed herein. Further, Luminant is continuing to review and analyze EPA's 1,323-page Final Transport Rule and the scores of new documents that EPA posted to the docket after finalizing the rule, and thus it reserves the right to supplement this request as appropriate.

of January 1, 2012, during its reconsideration proceeding and any judicial review of the rule, and extend the compliance deadlines to reflect at least the stay period.[4]

[4] As part of this stay, Luminant further requests that EPA stay its decision to remove CAIR allowances from individual accounts in EPA's Allowance Management System, which EPA has advised account holders it will do on October 14, 2011. EPA should leave CAIR allowances in individual accounts pending reconsideration and any judicial review.

Overview

Luminant is a competitive power generation business in Texas that, among other things, operates EGUs and sells electricity. Luminant Mining Company LLC, Big Brown Lignite Company LLC, and Oak Grove Mining Company LLC operate lignite mines that provide fuel to affiliated Luminant coal-fueled EGUs in the state. Luminant contributes approximately 31% of the electricity dispatched to Texas consumers and businesses by the Electric Reliability Council of Texas ("ERCOT"), the independent system operator that manages the state's competitive power market that serves the majority of the state. To accomplish this, Luminant owns and operates twelve coal-fueled EGUs at five generating plants in Texas (Big Brown, Martin Lake, Monticello, Sandow, and Oak Grove) that produce over 8,000 megawatts of power used by approximately three million Texans across the state. These coal plants together with other coal-fired generation in the state provide approximately 40% of the electricity consumed in ERCOT.

EPA did not propose to regulate Texas and Texas EGUs under the annual program in the rule when it made the rule available for public comment in August 2010, but, without any further notice, added Texas to the Final Transport Rule and imposed on Texas annual emissions budgets for SO_2 and NOx starting in 2012. There are several reasons that reconsideration and stay as to Texas are necessary:

► Texas is unique among the states for which an annual $PM_{2.5}$ FIP was promulgated in the Final Transport Rule. Texas was not among the states that EPA proposed to be included in a $PM_{2.5}$ FIP, nor did EPA propose annual SO_2 and NOx emissions budgets for Texas. As to those annual programs for Texas, the Final Transport Rule is a complete reversal of the proposed rule made available for public comment and is not the logical outgrowth of it. Thus, it is unlawful under governing federal law. EPA has changed both its conclusion and its rationale as to Texas, requiring additional public notice and comment. EPA admits that the comments it sought as to Texas in the proposed rule are "no longer relevant" given the substantial changes to the final rule, demonstrating further that the rule is invalid for failing to follow statutorily required notice and comment procedures.

► The Office of Management and Budget's ("OMB") report on interagency review observed that EPA has produced a "significantly different rule than originally proposed" given the addition of Texas and other changes, threatening the ability of regulated sources to meet the strict deadlines in the rule:

> *It is unclear if states and affected facilities will be prepared for a January 1, 2012 start date, especially given other changes that EPA is making in the draft final rule. For instance, modeling results used in the final rule are substantially different than those in the original August 2, 2010 Proposed Rule and subsequent notices. Six (6) States are being dropped from the proposed rule; Texas is being added; 3 States have their SO_2 Group status change; and the sheer magnitude of change to the budgets of*

> *all of the states results in a significantly different rule than originally proposed.*[5]

EPA should heed this warning in OMB's report by convening a reconsideration proceeding as to Texas and staying the impending compliance deadline, to allow for full public comment on the significant changes EPA has made.

► EPA's conclusion that Texas is "significantly contributing" to downwind nonattainment is questionable at best. EPA recently determined that the single downwind "receptor" identified as being impacted by Texas—the Granite City monitor in Madison County, Illinois—is in attainment with the 1997 $PM_{2.5}$ National Ambient Air Quality Standard ("NAAQS"). Thus, there is no nonattainment to address. In other words, the actual air quality monitoring data belie EPA's "predictive" modeling. Given Madison County's current attainment status and the fact that Texas EGU emissions are decreasing and have been for over a decade, a fact that even EPA admits, it strains logic for EPA to predict that this monitor will suddenly fall into nonattainment in just a few months as a result of Texas emissions.[6]

► Furthermore, the emissions reductions that EPA is requiring of Texas in the final rule are well in excess of what is necessary to address the state's alleged "significant contribution" to EPA's hypothetical downwind nonattainment. Thus, EPA is without authority to mandate these reductions. Under § 110(a)(2)(d)(i)(I) of the Clean Air Act, EPA has authority to require a state to eliminate the "amount" of emissions that "contribute significantly" to downwind nonattainment but cannot require anything more. *See North Carolina v. EPA*, 331 F.3d 896, 921 (D.C. Cir. 2008) ("[S]ection 110(a)(2)(D)(i)(I) gives EPA no authority to force an upwind state to share the burden of reducing other upwind states' emissions.").

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[5] *Summary of Interagency Working Comments on Draft Language under EO 12866 Interagency Review* ("OMB Summary of Interagency Working Comments"), Document EPA-HQ-OAR-2009-0491-4133 at 11 (posted July 11, 2011) (emphasis added).

[6] EPA concedes "that Texas EGUs have reduced their SO_2 emissions since 2005." Transport Rule Primary Response to Comments at 564 ("Response to Comments"), Document EPA-HQ-OAR-2009-0491-4513 (June 2011). These reductions are significant and are part of a fifteen-year downward trend in the state. According to EPA's Clean Air Markets Division, emissions of both SO_2 and NOx have steadily decreased in the Texas power sector over the period of 1995 to 2010. Specifically, SO_2 emissions decreased 26% from approximately 621,000 to 462,000 tons, while NOx emissions decreased 62% from 376,000 to 146,000 tons. Approximately 73,000 tons of the 159,000 tons of SO_2 reductions have come since 2005, with 57,000 tons (35%) attributable to Luminant alone. Further, the Texas power sector's emissions rates are below the U.S. average. Its 2010 SO_2 emission rate (0.30 lbs/MMBtu) was 24% lower than the national average of 0.40 lbs/MMBtu. Similarly, Texas's NOx emission rate (0.10 lbs/MMBtu) was 42% below the national average of (0.16 lbs/MMBtu). These data are shown on Exhibit 1.

- ► Indeed, EPA's annual SO_2 and NOx budgets for Texas exceed its authority (and are arbitrary on their face) because they are well below the amount of emissions that EPA itself concluded in the proposed rule would *not* cause any downwind significant contribution to nonattainment. In the proposed rule, EPA modeled Texas's downwind contribution to be below the "significance" level at an annual SO_2 emissions rate of 327,873 tons and an annual NOx rate of 159,738 tons for EGUs. 75 Fed. Reg. 45,210, 45,241-42 (Aug. 2, 2010). It is illogical that a reduction to 243,954 tons SO_2 and 133,595 tons NOx (the annual budgets that EPA seeks to impose on Texas) could be necessary to eliminate a "significant contribution" that did not exist at the higher emissions rates.

- ► As to Texas, EPA's FIP for the 1997 annual $PM_{2.5}$ NAAQS is premature and not authorized by statute. Just a month before issuing the Final Transport Rule, the record shows that EPA remained uncertain as to its authority to issue a FIP for Texas. EPA's uncertainty was warranted—it does not have legal authority to impose this FIP in Texas without first providing the state the opportunity to address the alleged "significant contribution" that EPA has only just now identified.

- ► Relatedly, EPA oversteps its authority in the Final Transport Rule by giving Texas and Texas sources no real choice regarding how to comply. Given the overly aggressive annual emissions budgets and the impending compliance deadline of January 1, 2012, the rule will effectively require the shutdown or de-rate of existing EGUs in Texas. This unit-level regulation by EPA violates the federal-state structure of the Clean Air Act and § 110(a) in particular.

- ► EPA's newly-revealed "remedy case" for Texas is based on flawed data and assumptions resulting in overly stringent requirements for Texas. As just one example, EPA's model assumes that natural gas-fueled EGUs that have been retired or mothballed (including one of Luminant's EGUs that has been completely demolished) will come online in a matter of months. This is unrealistic and drives a "remedy" that is unjustified and impossible to achieve by the January 1, 2012 compliance deadline without severe consequences. The only way to ensure that Texas's budgets (including its variability limit) are not exceeded is for sources in Texas to de-rate or shut down, resulting in lost generation, threats to reliability and public health and safety, job losses, and devastating impacts to small, rural communities in Texas that depend on these facilities to sustain their local economies. EPA has failed to consider these severe and dangerous impacts.

- ► EPA has failed to consider the reliability impacts to the unique stand-alone Texas electric grid from mandating, beginning in a matter of months, dramatic SO_2 and NOx emissions reductions from current levels. Given the looming deadline and the practical constraints that EPA has placed on allowance trading, EPA has in essence mandated reduced generation in the state. ERCOT, the independent system operator for the Texas electric grid that serves the majority of Texas, has already expressed concerns about the Final Transport Rule's impacts on reliability, and EPA should stay and reconsider the rule on this basis alone, in order to give all affected parties the legally required opportunity to comment on this aspect of the rule.

EPA should remedy these deficiencies by staying the rule and the impending compliance deadlines and undertaking reconsideration with respect to Texas. Reconsideration would allow interested parties, including Luminant, to review, analyze, and comment on EPA's new significant contribution analysis and new annual SO_2 and NOx emissions budgets for Texas, the new seasonal NOx budget for Texas, and the new data and assumptions underlying them.

Background

The Final Transport Rule is, in part, EPA's response to the D.C. Circuit's remand of the Clean Air Interstate Rule ("CAIR") in *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008). EPA promulgated CAIR in 2005 to require states to reduce emissions of SO_2 and NOx that EPA determined significantly contribute to nonattainment and interfere with maintenance of the 1997 NAAQS for $PM_{2.5}$ and/or ozone in a downwind state. 70 Fed. Reg. 25,162 (May 12, 2011). CAIR was a regional emissions allowance trading program that was intended to "provide states covered by the rule with a mechanism to satisfy their CAA section 110(a)(2)(D)(i)(I) obligations."[7] CAIR set a region-wide emissions budget based on the application of "highly cost effective" controls and allocated the budget to states based on heat input. *North Carolina*, 531 F.3d at 904.

In *North Carolina*, the D.C. Circuit held that EPA had "no statutory authority" for CAIR, because "EPA did not purport to measure each state's significant contribution to specific downwind nonattainment areas *and eliminate them in an isolated, state-by-state manner*." 531 F.3d at 907-08 (emphasis added). The Court held that "according to Congress, individual state contributions to downwind nonattainment areas do matter." *Id*. at 907. Thus, "EPA can't just pick a cost for a region, and deem 'significant' any emissions that can be eliminated more cheaply." *Id*. at 918. Instead, EPA's program "must actually require elimination of emissions from sources that contribute significantly and interfere with maintenance in downwind nonattainment areas." *Id*. at 908. The Court vacated CAIR in its entirety, but later issued a ruling to remand CAIR, without vacatur, thus leaving CAIR in place until EPA promulgated a new rule to replace it. *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008) ("*North Carolina II*").

While in part a response to *North Carolina*, the Final Transport Rule is more than simply an adjustment to CAIR. CAIR addressed EPA's <u>1997</u> annual and 24-hour $PM_{2.5}$ NAAQS. *North Carolina*, 531 F.3d at 903. The Final Transport Rule, in contrast, also addresses EPA's subsequent <u>2006</u> revision of the 24-hour $PM_{2.5}$ NAAQS, which lowered the standard from 65 to 35 $\mu g/m^3$. 75 Fed. Reg. at 45,219. EPA's 2006 revision of this NAAQS is the driver of the more stringent emissions limitations in the Final Transport Rule. *Id*. at 45,342 ("[T]here is no case where the annual standard drives the reduction deeper than would the 24-hour standard alone.").

EPA published its proposed new rule on August 2, 2010. 75 Fed. Reg. at 45,210. EPA proposed to limit SO_2 and NOx emissions from EGUs in 32 states in the eastern United States based on its finding that such emissions contribute significantly to nonattainment or interfere with maintenance of one of three NAAQS in one or more downwind states. *Id*. at 45,212. The

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[7] Section 110(a)(2)(D)(i)(I) provides that "[e]ach such [state] plan shall—(D) contain adequate provisions—(i) prohibiting … emissions activity within the State from emitting any air pollutant in amounts which will—(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard[.]" 42 U.S.C. § 7410(a)(2)(D)(i)(I).

three NAAQS considered by EPA were 1) the annual average $PM_{2.5}$ NAAQS issued in 1997; 2) the 24-hour average $PM_{2.5}$ NAAQS issued in 2006; and 3) the ozone NAAQS promulgated in 1997. *Id*.

With respect to the two $PM_{2.5}$ NAAQS, EPA chose to address upwind states' contribution by requiring reductions of SO_2 and NOx emissions from EGUs. EPA used a two-step process to determine which states to include and how much SO_2 and NOx emissions EGUs in those states would be required to eliminate. First, EPA used air quality modeling "to quantify individual states' contributions to downwind nonattainment and maintenance sites." *Id*. EPA used the Comprehensive Air Quality Model with Extensions ("CAMx") to model air quality for four scenarios: 1) a 2005 base year; 2) a 2012 base case with "no CAIR;" 3) a 2014 base case with "no CAIR;" and 4) a 2014 control case that reflected the emissions reductions from the proposed state budgets. *Id*. at 45,238.[8] EPA used the modeling for 2005 as the base year for projecting air quality for each of the three future year scenarios. *Id.* It used the 2012 base case modeling "to identify future nonattainment and maintenance locations and to quantify the contributions of emissions in upwind states" to $PM_{2.5}$ concentrations at those locations. *Id*. If a state's emissions were modeled to contribute "greater than 1 percent of the relevant NAAQS" at any downwind site in future years, the upwind state and the downwind site were considered "linked." *Id*. If a state's contribution did not exceed the threshold, its contribution was "found to be insignificant." *Id*. at 45,214.

If a state was found to be linked, EPA would move to the second step, which "identifies the portion of each state's contribution" that constitutes its significant contribution and interference with maintenance by using what EPA called "maximum cost thresholds, informed by air quality considerations." *Id*. at 45,233. EPA further broke this second step down into a four-step process. *Id*. at 45,272. In Step 1, "EPA developed a set of cost curves that show, at various cost increments, the available emissions reductions for EGUs in a state." *Id*. at 45,272. "EPA used IPM to identify costs for reducing [SO_2 and NOx] emissions from EGUs by modeling emissions reductions available at multiple cost increments." *Id*. At Step 2, EPA says it "uses an air quality assessment tool [AQAT] to estimate the impact of the upwind emissions reductions on downwind ambient concentrations." *Id*. at 45,273. At Step 3, EPA "examines the information developed in the first two steps to identify potential cost thresholds. It then uses a multi-factor assessment to identify which cost threshold or thresholds should be used to quantify states' significant contribution and interference with maintenance." *Id*. at 45,274. EPA claims Step 3 "responds" to the D.C. Circuit's holding in *North Carolina*. *Id*. At Step 4, EPA enshrines the reductions into state budgets. *Id*.

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[8] EPA used the National Emission Inventory ("NEI") with "significant augmentations" to develop the 2005 base case emissions that was used in the CAMx modeling. *Id*. at 45,239. EGU emissions in the 2012 and 2014 future years were projected using the Integrated Planning Model ("IPM"), which is a "multiregional, dynamic, deterministic linear programming model of the U.S. electric power section." *Id*. at 45,243.

In the proposed rule, EPA used this methodology to conclude that EGUs in the State of Texas were not significantly contributing to nonattainment or interfering with maintenance of either the annual or 24-hour $PM_{2.5}$ NAAQS in any downwind State. 75 Fed. Reg. at 45,255. As modeled by EPA, Texas EGUs' largest downwind contribution to nonattainment was 0.13 $\mu g/m^3$ as to the annual $PM_{2.5}$ standard (below EPA's 0.15 $\mu g/m^3$ threshold for inclusion) and 0.21 $\mu g/m^3$ as to the 24-hour standard (below EPA's 0.35 $\mu g/m^3$ threshold for inclusion). *Id*. at 45,255, 45,261. Thus, EPA did not propose to include Texas EGUs in the $PM_{2.5}$ aspect of the FIP and thus did not propose to regulate Texas EGUs in the annual program. *Id*. at 45,282. Accordingly, EPA did not propose an annual emissions budget for SO_2 or NOx for Texas. *Id*. at 45,291.

EPA did, however, request comment on a specific issue with respect to Texas. In the proposed rule, EPA requested comment on the "possibility" that emissions in non-covered states might increase based on changes in coal prices, prompting EGUs in the non-covered states to begin burning coal with higher sulfur content. 75 Fed. Reg. at 45,284. EPA speculated that "[i]f these price effects took place and if the rule is finalized as proposed, sources in states not covered by the proposed rule might choose to use higher sulfur coals. Increased use of such coals could thus increase SO_2 emissions in those states." *Id*. "For this reason, EPA [took] comment on whether Texas should be included in the program as a group 2 state." *Id*.

EPA's Administrator signed the final rule on July 6, 2011. As to Texas, EPA abandoned the possible "reason" for Texas's inclusion for which it sought comment. Apparently, further analysis showed that Texas was not among states whose emissions would increase based on changes in coal prices, if they were not included in the rule. FTR at 207. Instead, EPA reversed its prior decision that Texas EGUs were not "significantly contributing" to downwind nonattainment. EPA now determined, purportedly using new CAMx modeling and the four-step methodology from the proposed rule, that emissions from Texas EGUs will contribute significantly to nonattainment of the annual and daily $PM_{2.5}$ NAAQS in 2012 at a single monitor in Madison County, Illinois—the Granite City monitor, which is located 470 miles from the nearest Texas power plant. *See* Exhibit 2. EPA predicted Texas's contribution to this receptor would be 0.18 $\mu g/m^3$ (i.e., 0.03 $\mu g/m^3$ above the 0.15 $\mu g/m^3$ "significance" level set by EPA). EPA went further to impose an annual emissions budget for Texas and Texas EGUs of 243,954 tons of SO_2 and 133,595 tons of NOx per year, beginning on January 1, 2012, based on a purported $500 per ton cost threshold for both. *Id*. at 235 (Table VI.D-3).

Reasons that EPA Should Convene a Reconsideration Proceeding as to Texas

Luminant requests that EPA convene a proceeding pursuant to 42 U.S.C. § 7607(d)(7)(B) to reconsider its new "significant contribution" analysis for Texas and its resulting decision to impose an annual $PM_{2.5}$ FIP on the State; its newly-announced annual emissions budgets for both SO_2 and NOx and allowance allocations for Texas EGUs; and the new data and analysis in the Final Transport Rule that EPA claims support them.

Under the Clean Air Act, the Administrator "shall convene a proceeding for reconsideration of the rule" if the person raising the objection makes two showings: 1) that it was impracticable to raise the objection during the comment period or the grounds for the objection arose after the close of the public comment period; and 2) that the objections are of central relevance to the outcome of the rule. 42 U.S.C. § 7607(d)(7)(B). As discussed generally in Section I and specifically with respect to each substantive issue raised below, it was impracticable to raise the issues in this reconsideration request during the public comment period since EPA did not make the modeling information, its rationale for including Texas, or the annual emissions budgets available until issuance of the final rule. In addition, information about the attainment and status of Madison County, Illinois did not become available until after the close of the public comment period. The issues below are of central relevance to the outcome of the rule both in terms of Texas's inclusion in the annual emissions program as a threshold matter and, if included, the level of its annual SO_2 and NOx budgets. Because both prerequisites are met, EPA "lacks discretion not to address the claimed errors." *North Carolina v. EPA*, 531 F.3d 896, 927 (D.C. Cir. 2008).

I. It Was Impracticable for Luminant to Comment Because the Proposed Rule Addressed Neither the Basis for Including Texas in the Final Rule, nor a Proposed Remedy for Texas

As to Texas, the Final Transport Rule is a significantly different rule from the proposed rule and not the logical outgrowth of it. For regulations promulgated under the Clean Air Act to which 42 U.S.C. § 7607(d) applies, EPA must follow more stringent notice and comment requirements in addition to those contained in the Administrative Procedure Act ("APA"). 42 U.S.C. § 7607(d)(3). *See also Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 518-19 (D.C. Cir. 1983) ("Clean Air Act § 307(d)(3) requires a much more detailed notice of rulemaking [than does APA 553(b)(3).]").

Thus, the Clean Air Act, in contrast to the APA, requires that the EPA both "issue a proposed rule" and "give a detailed explanation of its reasoning at the 'proposed rule' stage as well [as in the final rule]." *Small Refiner Lead Phase-Down Task Force*, 705 F.2d at 519. The Clean Air Act also requires, *inter alia*, that EPA's proposed rule include "(A) the factual data on which the proposed rule is based; (B) the methodology used in obtaining the data and in analyzing the data; and (C) major legal interpretations and policy considerations underlying the proposed rule," 42 U.S.C. § 7607(d)(3), and, after issuance of the proposed rule, that EPA affirmatively update the rulemaking docket as new information becomes available. 42 U.S.C. § 7607(d)(4)(B)(i) ("All documents which become available after the proposed rule has been published and which the Administrator determines are of central relevance to the rulemaking shall be placed in the docket as soon as possible after their availability.").

These notice requirements are designed "(1) to ensure that agency regulations are tested via exposure to diverse public comment, (2) to ensure fairness to affected parties, and (3) to give affected parties an opportunity to develop evidence in the record to support their objections to the rule and thereby enhance the quality of judicial review." *Int'l Union, United Mine Workers of Am. v. Mine Safety and Health Admin.*, 407 F.3d 1250, 1259-60 (D.C. Cir. 2005). "It is not consonant with the purpose of a rule-making proceeding to promulgate rules on the basis of inadequate data, or on data that, [to a] critical degree, is known only to the agency." *Am. Radio Relay League, Inc. v. FCC*, 524 F.3d 227, 237 (D.C. Cir. 2008) (citing *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 393 (D.C. Cir. 1973)).

While EPA may promulgate a rule that is different from its prior proposals, it may not finalize its "unexpressed intentions." *Shell Oil v. EPA*, 950 F.2d 741, 751 (D.C. Cir. 1991). Where the final rule represents a "marked shift in emphasis" and is not implicit in the proposal, it is EPA's duty, not the public's, to anticipate a possible change and "to address it in its proposed regulations." *Id.*; *see also Int'l Union*, 407 F.3d at 1260 (final rule which is "surprisingly distant" from proposal is not a logical outgrowth). Interested parties are not expected to foresee EPA's "abandoning [its] proposed regulatory approach based on empirical research . . . simply because [it] invited commentary on a proposed rule that included a [very different approach]." *Id*.

EPA has violated these principles here as to Texas. Not only has EPA changed its conclusion as to whether Texas should be included in the rule, it has done so based on a rationale that is completely different from the limited rationale on which it sought comment for Texas. EPA pointed commenters down one path, and then abruptly took another path. EPA also produced annual emissions budgets for Texas for the first time in the final rule, where none appeared in the proposed rule. This is unprecedented in EPA's prior interstate transport rulemakings, in which EPA has always proposed a state's emissions budget for comment before finalizing it. EPA must remedy these deficiencies by convening a reconsideration proceeding as to Texas.

A. EPA has completely changed its analysis of Texas's "significant contribution" as between the proposed and final rule such that meaningful comment was not possible

In its proposed rule, EPA concluded that EGUs in the State of Texas were <u>not</u> significantly contributing to nonattainment or interfering with maintenance of either the annual or 24-hour $PM_{2.5}$ NAAQS in any downwind State. 75 Fed. Reg. at 45,255. Texas EGUs' largest downwind contribution to nonattainment was 0.13 $\mu g/m^3$ as to the annual $PM_{2.5}$ standard (below EPA's 0.15 $\mu g/m^3$ threshold for inclusion) and 0.21 $\mu g/m^3$ as to the 24-hour standard (below EPA's 0.35 $\mu g/m^3$ threshold for inclusion). *Id*. at 45,255, 45,261. Because EPA determined that Texas's contributions did not meet the requisite thresholds, EPA did not propose to include

Texas EGUs in the annual or 24-hour $PM_{2.5}$ aspect of the FIP and thus did not propose to regulate them in the annual program.

The only issue that EPA sought comment on with respect to Texas was the "possibility" that emissions in some states, including Texas, might increase after implementation of the Final Transport Rule, based on EPA's speculation about potential changes in coal prices and potential resulting SO_2 emissions increases. 75 Fed. Reg. at 45,284. EPA made clear that it was seeking comments "on whether Texas should be included in the program" as a group 2 state "**[f]or this reason**"—i.e., due to speculation about changes in coal prices leading to possible SO_2 emissions increases. *Id*. (emphasis added). On its narrow hypothetical, EPA received ample comment that the single concern it identified was unwarranted. And EPA apparently conducted further analysis after the close of the public comment period and determined that Texas was not one of the states whose emissions might increase based on changes in coal prices if it were not included in the rule. FTR at 207. EPA abandoned this "reason" in the Final Transport Rule, and does not offer it to justify Texas's inclusion. Accordingly, as EPA concedes, the comments that it solicited as to Texas are **"no longer relevant."** Response to Comments at 562 ("EPA notes that Texas is included in the final rule as a result of the state's contributions to down wind receptors in the updated base case modeling, thus, the comments on whether SO2 emissions in Texas might increase if the state were not covered (as was projected in the modeling for the proposal) are no longer relevant."). Obviously, if the comments EPA solicited are irrelevant to the final rule, then comments that are relevant to the final rule—which EPA did not solicit—could not have been raised during the comment period because the grounds for those comments arose after the public comment period closed.

Moreover, EPA's speculation about Texas in the proposed rule was based on analysis using EPA's simplified air quality assessment tool or "AQAT," not CAMx modeling. 75 Fed. Reg. at 45,284. The Final Transport Rule, however, does not rely upon the AQAT method to justify including Texas (which was the basis on which EPA sought comment as to Texas in the proposal), but instead uses substantially revised CAMx modeling to predict that Texas will significantly contribute to downwind nonattainment.[9] FTR at 201. The Final Transport Rule now concludes, based on CAMx, that emissions from Texas EGUs will contribute significantly to nonattainment of the annual and daily $PM_{2.5}$ NAAQS for a single monitor in Madison County, Illinois. This is the exact opposite conclusion that EPA reached using CAMx in the proposed rule. 75 Fed. Reg. at 45,255, 45,261.

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[9] Thus, even if it would have been possible to divine from the proposed rule EPA's intent to switch to a new rationale to include Texas (i.e., one using CAMx), EPA did not provide the tools necessary for the public to develop meaningful comments on Texas's alleged significant contribution. As OMB's interagency report recognizes, EPA's "modeling results used in the final rule are substantially different than those in the original August 2, 2010 Proposed Rule and subsequent notices." OMB Summary of Interagency Working Comments at 11. This is at least in part due to the fact that EPA made many substantive changes to both its CAMx modeling and AQAT. *See, e.g.*, FTR at 102-03, 145, 196-200 ("EPA made significant improvements to the air quality assessment tool").

EPA thus requested comment on one rationale for including Texas, and then finalized a rule using an entirely different rationale—a classic bait-and-switch. EPA changed both the method of analysis and the outcome. EPA could have easily provided the public with updated information about its analysis for Texas through a supplemental notice. It issued three Notices of Data Availability ("NODA") after the proposed rule, but none of them disclosed any data or model runs justifying Texas's inclusion or indicated that EPA was considering developing a Texas budget. By failing to disclose its new analysis and supporting information for Texas as soon as that information became available, EPA violated § 307(d)(4)(B)(i). EPA has used "the rulemaking process to pull a surprise switcheroo on regulated entities," including Luminant. *Envt'l Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005) (vacating EPA rule for failure to comply with notice requirements). EPA's proposed rule sent commenters down the wrong track, and, given EPA's failure to update the record or provide a supplemental notice, there was no way that commenters could have provided meaningful comment on EPA's final methodology and conclusions for Texas.

B. EPA did not propose annual emissions budgets for Texas, in contrast to every other state that has been given a final budget in this and other EPA interstate transport rulemakings

In addition, and of critical importance, EPA did not propose or even discuss in its proposed rule what emissions budgets would apply to the State of Texas if it were to be included in the annual program; in contrast, it proposed a very specific budget for every other state now included in the Final Transport Rule. 75 Fed. Reg. at 45,291, 45,294. This is not surprising considering the fact that EPA's own findings showed that Texas did not significantly contribute to nonattainment or interfere with maintenance of either $PM_{2.5}$ NAAQS in any downwind area. The only logical conclusion to draw from this was that, should EPA change its mind to include Texas, it would propose an emissions budget for comment—not issue budgets for the first time in a final rule. This, in fact, is what EPA has appropriately done for six other states that EPA did not include in the proposed rule for ozone but is now proposing to include. For these six other states, EPA has issued a supplemental notice of proposed rulemaking ("SNPR") and is accepting public comment on the particular issues involved in those states' inclusion in an ozone FIP. 76 Fed. Reg. 40,662 (July 11, 2011). There is no good reason that EPA cannot do the same for Texas as to $PM_{2.5}$, and indeed EPA has offered no such reason.[10]

EPA's position that the state budgets it published in the proposed rule are merely "illustrative" is not credible and appears to be a belated attempt to justify EPA's unprecedented

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[10] Apparently, EPA intended to include Texas in a SNPR at least with respect to the 24-hour $PM_{2.5}$ NAAQS, but, for no obvious reason, changed its mind at the last minute before signing the Final Transport Rule. *See Part of E.O. 12866 Review Pertaining to Final Transport Rule*, Document EPA-HQ-OAR-2009-0491-4552 at 36 (June 16, 2011 draft of preamble stating that "EPA is also requesting comment, in a supplemental notice of proposed rulemaking, on its conclusion that Texas also significantly contributes to nonattainment or interferes with maintenance of the 24-hour $PM_{2.5}$ NAAQS in another state.").

decision here to finalize state emissions budgets without taking any public comment on them. FTR at 29-30. Moreover, this post hoc rationalization directly contradicts EPA's repeated assertion in the proposed rule that it was using a "state-specific" approach to address the D.C. Circuit's holding in *North Carolina*. *See, e.g.*, 75 Fed. Reg. at 45,290. In fact, there was nothing specific at all to Texas's annual budget in the proposed rule.

The budgets are the critical and operative aspect of the rule, and EPA has always treated them that way. In prior transport rulemakings, EPA has proposed a specific budget for every state included in the final rule and allowed for public comment on those budgets. For instance, EPA's final NOx SIP Call created an emission allowance cap-and-trade program. In that rule, EPA only finalized state emission budgets for states for which it had proposed emission budgets in the proposed rule. *Compare* 62 Fed. Reg. 60,318, 60,361 (Nov. 7, 1997) *with* 63 Fed. Reg. 57,356, 57,439 (Oct. 27, 1998). Accordingly, each state included in that final rule was provided an equal opportunity to review and comment on this aspect of EPA's NOx SIP Call program. Similarly, for EPA's NOx and SO_2 cap-and-trade program in CAIR, all states receiving final annual SO_2 and annual NOx budgets were provided with proposed budgets in EPA's proposed rule. *Compare* 69 Fed. Reg. 4,566, 4,619-4,621 (Jan. 30, 2004) *with* 70 Fed. Reg. 25,162, 25,230-25,231 (May 12, 2005). EPA's deviation from its consistent past practice in this instance demonstrates the inadequacy of the proposed rule in providing fair notice as to Texas. Given EPA's past practice, Texas stakeholders' only reasonable expectation was that EPA would issue a supplemental notice providing proposed budgets for Texas before it sought to finalize them. There is no reason that EPA could not have done so with respect to Texas (or do so now, as it has for six other states).

Not only did Luminant have no notice that EPA was developing annual budgets for Texas for SO_2 and NOx, there was no basis to comment on the details of such budgets. As to Texas in particular, EPA did not publish any variability analyses, individual unit allocations, new unit set asides, AQAT results, modeling inputs and assumptions, and other information that EPA claims is relevant to annual emissions budgets. Nor could Luminant comment on the impacts of such budgets on its operations, electric reliability, jobs for Texans, electricity prices, or consequential effects on the overall economy—which, as discussed below, are substantial. Luminant, on its own, simply cannot generate emissions budgets out of thin air, nor should it have to guess at budgets that EPA might propose. The agency's analysis and calculations as to Texas were not provided for public comment, thus denying commenters the opportunity to provide meaningful input. *Solite Corp. v. EPA*, 952 F.2d 473, 499-500 (D.C. Cir.1991) (ordering EPA to conduct reconsideration and provide additional notice and comment based on late disclosure of data); 42 U.S.C. §§ 7607(d)(3)(A), 7607(d)(4)(B)(i). As the D.C. Circuit aptly stated in a similar situation, "something is not a logical outgrowth of nothing." *Envt'l Integrity Project*, 425 F.3d at 996 (internal citation and quotation omitted). That is certainly the case here—EPA's inclusion of Texas in the final rule as it pertains to $PM_{2.5}$ and its SO_2 budget of 243,954 tons and annual NOx budget of 133,595 tons for Texas are not the logical outgrowth of a proposed rule that did not include Texas and proposed *no budgets at all* for Texas. Further, the Final Transport Rule failed to provide any justification—let alone a reasoned justification—for treating Texas differently than every other state with respect to proposed emissions budgets. This constitutes both an arbitrary departure from past practices, *FCC v. Fox Television Stations, Inc.*, 129 S. Ct. 1800, 1811 (2009); *Davila-Bardales v. INS*, 27 F.3d 1, 5-6 (1st Cir. 1994), and a fundamental failure to treat similarly situated parties the same, *Indep. Petroleum Ass'n v. Babbitt*, 92 F.3d 1248, 1260 (D.C. Cir. 1996); *ANR Pipeline Co. v. FERC*, 71 F.3d 897, 901 (D.C. Cir. 1995).

II. EPA's new annual emissions budgets for Texas exceed EPA's authority under Section 110 of the Clean Air Act and run afoul of the holding in *North Carolina*

Not only did EPA fail to give adequate notice of its annual emissions budgets for Texas, the budgets that it has finalized overstep the agency's statutory authority for two independent, but related, reasons. First, Texas is not contributing to nonattainment with the 1997 $PM_{2.5}$ NAAQS at the downwind "receptor" that EPA has identified for Texas. Actual air quality data show that this monitor—the Granite City monitor in Madison County, Illinois—is, in fact, in attainment. Nor is it reasonable to predict that this monitor will be in nonattainment in just a few short months, as EPA has modeled. Second, the annual SO_2 and NOx emissions budgets that EPA has imposed on Texas far exceed in their requirements any prohibition of Texas's miniscule "significant contribution" and instead require substantially deeper emissions cuts, and therefore go beyond EPA's limited statutory authority to address interstate transport.[11]

A. Texas is not contributing, and will not contribute, to nonattainment in Madison County, Illinois

Texas is included in the annual emission program in the Final Transport Rule for one reason—EPA's modeling that predicts Texas will contribute to nonattainment with the 1997 annual $PM_{2.5}$ NAAQS at one, and only one, downwind receptor—the Granite City monitor in Madison County, Illinois. FTR at 152.[12] The amount of contribution attributable to Texas in EPA's modeling is miniscule—just 0.03 $\mu g/m^3$ above EPA's significance level (0.18$\mu g/m^3$ v. 0.15 $\mu g/m^3$). *Id*. at 149.

EPA's statutory authority to address this contribution through mandatory revisions to Texas's SIP or a FIP derives from § 110 of Clean Air Act. Section 110 "governs the interplay

[11] Because EPA's new "significant contribution" analysis, annual emissions budget for Texas, and AQAT results for Texas were not disclosed until the Final Transport Rule, Luminant did not raise, and could not have raised, the issues raised in this section during the public comment period. In fact, it appears that EPA did not disclose its AQAT analysis and results for any states in time for the public to comment on them. As discussed above, 42 U.S.C. § 7607(d)(3) and § 7607(d)(4)(B)(i) require EPA to disclose the factual data and methodologies upon which its rules are based. Its failure to do so is a violation of the notice and comment provisions applicable to Clean Air Act rulemakings. Further, EPA's determination that Madison County, Illinois, is in attainment is ground for reconsideration that arose after the close of the public comment period.

[12] Nor does EPA find that Texas is "interfering with maintenance" at any downwind $PM_{2.5}$ receptor.

between the states and EPA with respect to the formulation and approval of [SIPs]." *Virginia v. EPA*, 108 F.3d 1397, 1406 (D.C. Cir. 1997). Sections 110(a)(2)(H) and 110(k)(5) in particular provide that states can be required to revise SIPs only when existing provisions are found "substantially inadequate," and then only "as may be necessary" to attain and maintain the NAAQS. 42 U.S.C. §§ 7410(a)(2)(H) & (k)(5). As the D.C. Circuit has explained in reviewing EPA's prior interstate transport rules, EPA is a creature of statute and has only the authority conferred upon it by statute—namely, the Clean Air Act. *North Carolina*, 531 F.3d at 922 (quoting *Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001)).

Here, a FIP addressing the interstate transport of emissions from Texas is not necessary to attain or maintain the NAAQS in Madison County, Illinois, because that area is already in attainment. On May 23, 2011, EPA published in the *Federal Register* its "final action determining that the Saint Louis fine particle ($PM_{2.5}$) nonattainment area [i.e., the nonattainment area that includes Madison County] … has attained the 1997 annual $PM_{2.5}$ National Ambient Air Quality Standard." 76 Fed. Reg. at 29,652. As a result, because the sole receptor identified for Texas is attaining the 1997 $PM_{2.5}$ NAAQS, the Texas SIP is neither "substantially inadequate" nor are further reductions "necessary" to address contributions to nonattainment of air quality standards. This actual data (which was verified and acted on by EPA) further calls into question the validity and reliability of EPA's modeling in the Final Transport Rule that predicts this monitor will be in nonattainment in just a few months as a result of Texas emissions, and EPA has not explained the discrepancy between its modeling and real world conditions.

Nor is it reasonable to predict that Madison County will be in nonattainment due to interstate transport from Texas in just a few short months. Fine-scale modeling, not considered by EPA in the Final Transport Rule, has determined that any nonattainment modeled in 2012 for the Granite City monitor is the result of emissions from a large local steel mill, not upwind emissions from Texas. The Granite City monitor itself is an anomaly—it is the only one of five monitors in the Madison County area that is predicted to be in nonattainment for the annual $PM_{2.5}$ NAAQS by EPA's modeling; all the other monitors modeled in attainment.[13] The reason, according to fine-scale modeling conducted as part of an EPA state and local focus group, is a local U.S. Steel mill—*not* "regional transport" from Texas.[14] The report on this modeling explained:

> A somewhat more refined approach to wind direction analysis at the Granite City monitoring site evaluated separate local and regional components of total $PM_{2.5}$ mass. $PM_{2.5}$ measurements from the Granite City site were compared to measurements at a second site in downtown St. Louis to identify time periods

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[13] *See* Exhibit 3. It defies logic that Texas's emissions from 470 miles away could impact just one monitor in Illinois but not others just a few miles away from it, and EPA does not explain how this could be the case. Clearly, local sources are the problem, not interstate transport.

[14] *Assessment of Local-Scale Emissions Inventory Development by State and Local Agencies*, U.S. EPA, Research Triangle Park, at 3-6, 3-7 (Oct. 2010) (Exhibit 4).

> when the Granite City site showed "excess" $PM_{2.5}$ concentrations above levels that would be attributable to regional transport and urban sources (e.g., motor vehicles). Measurements from these time periods were combined with surface meteorological data to identify source regions contributing to the excess $PM_{2.5}$. This analysis showed that excess $PM_{2.5}$ was observed at the Granite City site when winds were from the south and southwest, indicating impacts from a large steel mill in the vicinity.[15]

An examination of the modeling results shows that the emissions from this local source are the reason this monitor would model in nonattainment. The modeling projected a $PM_{2.5}$ design value for this Madison County monitor of 15.23 $\mu g/m^3$ with the U.S. Steel mill included (i.e., nonattainment), but a value of 13.55 $\mu g/m^3$ (i.e., attainment) with this source "zeroed out."[16] The conclusion was that this U.S. Steel facility was "primarily responsible for excess emissions." *Id*. This is further demonstrated by data collected at the monitor and the steel mill from 2005-2009. When the mill reduced production in 2009,[17] the Granite City monitor was easily in attainment with the 1997 $PM_{2.5}$ NAAQS, as the following table illustrates:

Parameter/Year	2005	2006	2007	2008	2009
U.S. Steel GCW PM Emissions (tpy)[18]	1,119	1,122	1,103	1,039	372.8
$PM_{2.5}$ mean at Granite City monitor ($\mu g/m^3$)[19]	18.2	16.3	15.2	15.7	11.3

[15] *Id.*

[16] Jeffrey Sprague, *Granite City, IL PM2.5 Nonattainment: Regional and Local-Scale Modeling, Data Analysis, and Emissions Control Developments*, Illinois EPA (Bureau of Air), July 27, 2010, *available at* http://www.epa.gov/ttnchie1/local_scale/ as an appendix to the October 2010 Assessment of Local-Scale Inventory Development by State/ Local Agencies, Final Report.

[17] Although this mill has reportedly resumed operations in 2010, it is doing so under a Memorandum of Understanding ("MOU") with the Illinois Environmental Protection Agency "with the specific intent of reducing the emissions of particulate $matter_{2.5}$ (PM2.5)," and a revised Title V operating permit. *See* Exhibit 5; U.S. Steel Corp., Title V- Clean Air Act Permit Program (CAAPP) Permit- Revised, I.D. No. 119813AAI, May 2, 2011, *available at* http://yosemite.epa.gov/r5/in_permt.nsf/33cf5ec06b4d2f1d8625763f0052ba7c/ba4fceebf2e510e8862578db00565183!OpenDocument. Despite its commitment to consider all non-CAIR enforceable emissions limitations in its modeling, EPA failed to consider in its base case the emissions reductions that will result from U.S. Steel's MOU with Illinois. If these reductions were properly reflected in EPA's base case modeling, the Granite City monitor would likely monitor in attainment, eliminating any basis for including Texas in the Final Transport Rule.

[18] Source: Statement of Basis for a Planned Revision of the Clean Air Permit Program (CAAPP) Permit for: U.S. Steel Corporation, Granite City Works, at 10 (Exhibit 6).

This monitor plainly is not a reasonable choice by which to judge the effects of upwind emissions, and it should not have been used as a receptor in the Final Transport Rule. At a minimum, given the change in information since EPA conducted its modeling, EPA should and must re-open the public comment period to consider the current attainment status of Madison County and this additional fine scale modeling for the Granite City monitor and to adjust its modeling and assumptions accordingly to determine if Texas will, in fact, "significantly contribute" to downwind nonattainment. 42 U.S.C. § 7607(d)(4)(B)(i) (requiring new data "be placed in the docket as soon as possible after their availability"). *See also Catawba County, North Carolina v. EPA*, 571 F.3d 20, 45 (D.C. Cir. 2009) ("An agency does, however, have an obligation to deal with newly acquired evidence in some reasonable fashion."); *WWHT, Inc. v. FCC*, 656 F.2d 807, 819 (D.C. Cir. 1981) ("[A]n agency may be forced by a reviewing court to institute rulemaking proceedings if a significant factual predicate of a prior decision on the subject (either to promulgate or not to promulgate specific rules) has been removed.").

Finally, not only has EPA failed to account for local sources at the Granite City monitor, its base case overstates Texas's upwind emissions for two reasons. First, EPA's decision to discount post-2005 emission reductions and air quality improvements resulting from CAIR, *see* 75 Fed. Reg. at 45,233/3, is an illogical and unreasonable policy decision. *See* Comments of UARG, Document EPA-HQ_OAR-2009-0491-2756.1, at 50-53. Second, although EPA claims that its baseline modeling considered "reductions made to comply with permanent limitations" (FTR at 74), EPA failed to follow this methodology for Texas. For example, EPA omitted from its base case for Texas two flue gas desulfurization systems ("scrubbers") on the Lower Colorado River Authority's Fayette Unit 1 and Unit 2, and thus Texas's emissions were overstated by approximately 20,000 tons. These scrubbers were not installed to meet CAIR requirements, but reportedly were "part of a deal with regulators to replace tubes lining the boiler that were corroding from constant wear."[20] Thus, even under its own "CAIR-free" methodology, EPA erred in not including the reductions from those scrubbers in its base case, casting further doubt on EPA's prediction that Texas EGUs will "significantly contribute" to downwind nonattainment.

B. The drastic emissions reductions required of Texas exceed the "significant contribution" modeled by EPA and are therefore unlawful

Further, even if EPA's prediction that Texas will significantly contribute to nonattainment at the Granite City monitor is correct, EPA's annual SO_2 and NOx budgets impose limits that go beyond Texas's small contribution and therefore exceed the agency's statutory authority under § 110(a)(2)(d)(i)(I) of the Clean Air Act.

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[19] Source: Illinois Environmental Protection Agency, 2009 Annual Air Quality Report, at 56, *available at* http://www.epa.state.il.us/air/air-quality-report/2009/index.html.

[20] Asher Price, *LCRA adds scrubbers to clean sulfur dioxide from plant emissions*, Austin American-Statesman (Aug. 2, 2011), *available at* http://www.statesman.com/news/local/lcra-adds-scrubbers-to-clean-sulfur-dioxide-from-1681702.html.

Under § 110(a)(2)(d)(i)(I), even when it is "necessary" to require upwind states to address downwind nonattainment, EPA is not authorized to require reductions beyond the "amounts which will" "significantly contribute" to the downwind nonattainment. 42 U.S.C. § 7410(a)(2)(D)(i)(I). Section 110(a)(2)(D)(i)(I) provides that "[e]ach such plan shall—(D) contain adequate provisions—(i) prohibiting … emissions activity within the State from emitting any air pollutant in amounts which will—(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard[.]" *Id*. Accordingly, in *North Carolina v. EPA*, the D.C. Circuit found that EPA had "no statutory authority" for CAIR, because "EPA did not purport to measure each state's significant contribution to specific downwind nonattainment areas *and eliminate them in an isolated, state-by-state manner*." 531 F.3d at 907-8 (emphasis added). The Court held that "according to Congress, individual state contributions to downwind nonattainment areas do matter." *Id*. at 907. Thus, "EPA can't just pick a cost for a region, and deem 'significant' any emissions that can be eliminated more cheaply." *Id*. at 918.

EPA's annual emissions budgets for Texas in the Final Transport Rule violate these statutory limitations. EPA, in effect, claims it is adhering to the Court's holding in *North Carolina* because it is placing states in two groups, not just one. FTR at 17-25, 175-83, 269-74. But the same problem persists. EPA has in fact used the same blunt instrument that the D.C. Circuit rejected in CAIR—uniform cost thresholds—to identify and mandate the amount of air pollution that a state must eliminate. And the result is even more impermissible—uniform controls across multiple states without any consideration of whether those controls, for any individual state, improperly go beyond eliminating that state's significant contribution to downwind nonattainment and therefore impose controls which EPA has no statutory authority to require. The result as to Texas is that the state is required to reduce well *below* the "amount" of its modeled significant contribution, even though EPA's *only* pertinent authority is to "prohibi[t] . . . emissions activity . . . in amounts which will . . . contribute significantly" to nonattainment." 42 U.S.C. § 7410(a)(2)(D)(i)(I).

At the same time, other states contributing to the Madison County, Illinois receptor are not required to reduce below their significant contribution at all but are instead allowed to continue to contribute downwind emissions above the significance levels. EPA identified eight other upwind states that also contributed significantly to nonattainment at that monitor (Indiana, Iowa, Kentucky, Michigan, Missouri, Ohio, Tennessee, and Wisconsin). FTR at 150-52. Based on their cost curves, EPA placed each of these states in either the SO_2 program's Group 1 or Group 2. Group 1 states are required to reduce their emissions to a level that would be achieved applying controls at $2,300, and Group 2 states at $500. But EPA does not require all of these states to eliminate their "significant contribution," as demonstrated by EPA's Air Quality Assessment Tool ("AQAT"). At Step 2 of its methodology, EPA says it uses AQAT "to estimate the impact of the upwind state reductions on downwind state air quality at different cost-per-ton levels."[21] EPA ran AQAT for each downwind monitor, including Madison County, Illinois, to

[21] *Significant Contribution and State Emissions Budgets Final Rule TSD* ("Significant Contribution TSD") at 2, Document EPA-HQ-OAR-2009-0491-4456 (posted July 11, 2011).

see what the ambient air quality at the monitor would be if each upwind state (and the host state) applied the cost controls for their respective group (i.e., Group 1 or 2). Significant Contribution TSD at 19.

However, EPA did not use the output of AQAT to determine if *each State* has eliminated its significant contribution to nonattainment (i.e., reduced its emission below 1% of the relevant NAAQS). Instead, it only looked at whether the downwind site would achieve attainment following the application of uniform cost controls in the upwind states. Significant Contribution TSD at 29 ("For annual $PM_{2.5}$ in 2014[,] [n]o monitors are estimated to have remaining nonattainment problems at the $2,300/ton SO_2 cost threshold."); FTR at 216 ("For Group 2 states, the air quality assessment tool projected that the SO_2 reductions at this first cost threshold assessed *would resolve the nonattainment and maintenance problems* for all of the areas to which the following states are linked: . . . Texas.") (emphasis added). Further, an examination of the AQAT results shows that, while the application of uniform cost reductions within the two groups is projected to result in no further attainment problems at the Granite City monitor in Madison County, Illinois, it does not result in each contributing state eliminating its significant contribution and results in some states (including Texas) over-reducing. Thus, at $500/ton, Texas's contribution to the Madison monitor drops to 0.127 $\mu g/m^3$ (from 0.18 $\mu g/m^3$).[22] In other words, EPA's $500/ton threshold is requiring Texas to overreduce to approximately 16% below the significance level (0.15 $\mu g/m^3$). However, many of the other states that are modeled to significantly contribute to nonattainment at this Madison County monitor are not eliminating their significant contribution, even at the $2,300/ton cost level. For example, even at $2,300/ton, Indiana is still contributing 0.293 $\mu g/m^3$; Illinois 0.612 $\mu g/m^3$; and Missouri 0.642 $\mu g/m^3$. Thus, EPA is <u>not</u> eliminating "air pollutant[s] in amounts which will—(I) contribute significantly to nonattainment." 42 U.S.C. § 7410(a)(2)(D)(i)(I). It is seeking instead to completely eliminate nonattainment in the downwind state through the application of uniform cost controls and *overcontrolling* in some states in order to enable it to *undercontrol* other states and more equitably (in EPA's view) spread the burden. That is not what § 7410(a)(2)(D)(i)(I) authorizes EPA to do—as the *North Carolina* decision confirms. 531 F.3d at 921 ("EPA's redistributional instinct may be laudatory, but section 110(a)(2)(D)(i)(I) gives EPA no authority to force an upwind state to share the burden of reducing other upwind states' emissions. Each state must eliminate its own significant contribution to downwind pollution.").

In short, Texas's minimal and borderline contribution cannot support EPA's massive required reductions. *See* Exhibit 7. The reductions do not address only the "amounts" of Texas emissions that significantly contribute to downwind nonattainment. In fact, using the more rigorous CAMx model in its proposed rule, EPA itself concluded that Texas would not significantly contribute to downwind nonattainment in any state at an SO_2 emission level of 327,873 tons annually. *See* 75 Fed. Reg. at 45,241, 45,255.[23] EPA's 243,954 tons SO_2 budget

[22] *See* Annual $PM_{2.5}$ AQAT, Document EPA-HQ-OAR-2009-0491-4458 (posted July 11, 2011).

[23] The record as it stands now does not provide adequate support for *any* annual budgets to be set for Texas. EPA's modeling is itself internally inconsistent and unreliable. For

for Texas is clearly overcontrolling Texas sources. Moreover, given that this Madison County monitor is currently in attainment, the most that EPA could justify as a remedy is to cap Texas emissions at their 2010 levels—462,000 tons of SO_2 and 146,000 tons of NOx—which represent significant reductions achieved by Texas sources in the last fifteen years. Exhibit 1. EPA is not authorized to make Texas go further, just so a single monitor in Madison County can be *modeled* in attainment. The result is exactly what the Court rejected in *North Carolina*: "EPA can't just pick a cost for a region, and deem 'significant' any emissions that can be eliminated more cheaply." 531 F.3d at 918. Although EPA attempts to dress up its methodology here with lip service to each individual state's contribution, it is only repeating the mistake it made in CAIR.

III. As to Texas, EPA has not met the statutory prerequisites for a Federal Implementation Plan

Not only is EPA seeking to require more emissions reductions from Texas EGUs than §110 authorizes, it is doing so in a manner—by way of a Federal Implementation Plan ("FIP")—that further violates § 110. EPA has put the cart before the horse. The Clean Air Act requires that states first address nonattainment with the NAAQS *within their own borders*, and, only after that has occurred, does the statute authorize EPA to find that other states' SIPs are substantially inadequate to prohibit "significant contribution" to any remaining nonattainment in the downwind state. EPA's premature FIP displaces state authority under the statute and is contrary to the federal-state partnership that Congress established under the Act generally and with respect to interstate transport in particular.[24]

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example, EPA first modeled Texas's downwind contribution to be 0.13 $\mu g/m^3$ at an annual SO_2 emissions rate of 327,873 tons. 75 Fed. Reg. at 45,255. Subsequent EPA modeling using AQAT found Texas's downwind contribution to be substantially the same (0.126 $\mu g/m^3$) at a rate of 281,298 tons of SO_2 annually. *See* Annual $PM_{2.5}$ AQAT, Document EPA-HQ-OAR-2009-0491-4458, Significant Contribution TSD at 15. This does not make sense. EPA has not explained how Texas could be modeled to have the same impact at such different emission levels. The only possible explanation is a flaw in EPA's modeling or methodology, perhaps with its new and untested AQAT. At a minimum, EPA must address this inconsistency and allow for full public comment on it.

[24] The issues addressed in this section were raised generally with EPA during the public comment period by the Utility Air Regulatory Group, of which Luminant is a member and whose comments Luminant adopted, and Luminant raised questions about the timing and sequencing of EPA's FIP in general in its own comments. However, because EPA did not propose a FIP for Texas as to the $PM_{2.5}$ NAAQS and did not specify the basis for a FIP as to Texas in the proposed rule, it was impracticable to raise the Texas-specific issues addressed here. Indeed, the rulemaking record shows that there was internal uncertainty as to EPA's FIP authority for Texas even as EPA was drafting the Final Transport Rule well after the close of the public comment period. As late as June 2011, EPA had intended to base its FIP for Texas on the 2006 $PM_{2.5}$ NAAQS, but inexplicably changed its mind. *See Status of CAA 110(a)(2)(D)(i)(I) SIPs Final Rule TSD*, Document EPA-HQ-OAR-2009-0491-4297 (June 2011) (posted July 11, 2011).

Under the statute, states are given the primary responsibility for air pollution control from sources within their borders. *See* 42 U.S.C. § 7407(a); 42 U.S.C. § 7401(a)(3) ("[A]ir pollution prevention . . . is the primary responsibility of States and local governments."). EPA may rescind a state's authority over sources within its borders by issuing a FIP in only limited circumstances, *i.e.*, only "*after* the Administrator—(A) finds that a state has failed to make a *required* submission . . . or (B) disapproves a State implementation plan submission in whole or in part." 42 U.S.C. § 7410(c) (emphasis added). Neither of these prerequisites has been met here.

Here, EPA claims to have the authority to issue a FIP for Texas under §110(c) as to the 1997 $PM_{2.5}$ NAAQS. FTR 29-31.[25] EPA claims that a "finding of failure" it made in April 2005 with respect to this NAAQS started a "two-year clock" within which EPA was required to issue a FIP as to interstate transport. 75 Fed. Reg. at 45,226 (citing 70 Fed. Reg. 21,147 (Apr. 25, 2005)). The finding of failure is further premised on EPA's view that states were required to address interstate transport within three years of the issuance of the 1997 $PM_{2.5}$ NAAQS and, thus, as of April 2005, "[s]tates should already have submitted [$PM_{2.5}$] SIPs that satisfied the section 110(a)(2)(D)(i) requirement related to interstate transport." 70 Fed. Reg. at 21,148. EPA is incorrect. As of April 2005, Texas had not failed to make a *required* submission as to the 1997 $PM_{2.5}$ NAAQS (and neither has EPA disapproved Texas's submission[26]), and thus the "two-year FIP clock" in § 110(c) was not and has not been triggered.

Specifically, § 110(a)(1), which sets the three-year deadline for state plan submittals that EPA relies on, only applies to a SIP's "implementation, maintenance and enforcement of

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EPA's final basis for issuing a FIP as to Texas was not formulated until July 2011 and not made available to the public until after the Final Transport Rule was signed. *See Status of CAA 110(a)(2)(D)(i)(I) SIPs Final Rule TSD*, Document EPA-HQ-OAR-2009-0491-4527 (July 2011) (posted July 12, 2011).

[25] EPA's claim that including Texas in the Final Transport Rule only requires a FIP as to the 1997 $PM_{2.5}$ NAAQS is not well-founded. The Final Transport Rule is a single rule designed to address both the 1997 $PM_{2.5}$ NAAQS and the more stringent 2006 $PM_{2.5}$ NAAQS simultaneously with the same annual emissions budgets. Given the manner in which EPA developed state budgets, using uniform cost curves, EPA cannot say that its budgets for Texas only address the 1997 $PM_{2.5}$ NAAQS. In fact, EPA made clear in its proposed rule that the more stringent 2006 standard was the driver of state emissions budgets. 75 Fed. Reg. at 45,342 ("[T]here is no case where the annual standard drives the reduction deeper than would the 24-hour standard alone."). Because EPA simultaneously addressed both 1997 and 2006 $PM_{2.5}$ NAAQS with a single budget for Texas, it was required to have FIP authority for both. EPA has not disapproved Texas's proposed SIP revision for the 2006 standard, and, as a result, it lacks authority to issue a FIP that in effect addresses that standard.

[26] In an October 2008 notice, EPA determined that Texas's infrastructure SIP submittal for 1997 $PM_{2.5}$ NAAQS was administratively complete. 73 Fed. Reg. 62,902 (Oct. 22, 2008). But EPA has never acted to disapprove that submission.

[primary NAAQS] … in each air quality control region (or portion thereof) *within such State*." 42 U.S.C. § 7410(a)(1) (emphasis added). Section 110(a) does not establish any deadline for submittal of SIPs that address areas *outside of* such state. The "good neighbor" provision in § 7410(a)(2)(D) deals with NAAQS attainment and maintenance in another state and is only properly considered after states have submitted SIP revisions to address the NAAQS within their own borders. Section 110(a)(1) confirms that the adequacy (or inadequacy) of a state's plan to eliminate significant contributions in other states can be addressed only *after* those other states have been required to address contributions of sources located within their own borders.

Accordingly, when EPA issued the 1997 PM2.5 NAAQS, Texas did not have an obligation to submit a SIP revision that addressed interstate transport within three years. The first order of business for all states was to address attainment of the 1997 $PM_{2.5}$ NAAQS within their own borders.[27] 42 U.S.C. § 7410(a)(1). And it was not until January 2005 that Madison County, Illinois, was designated as nonattainment with the 1997 $PM_{2.5}$ NAAQS, thus triggering the State of Illinois' obligation to address the nonattainment through emissions reductions at sources in the state.[28] Illinois' revision to its SIP to address the nonattainment then became due by January 2008. 42 U.S.C. § 7502(b).[29]

It was not until after that revision was due and evaluated that upwind states had any obligation to assess and remedy their "significant contribution." Under § 110, once a state

[27] As EPA has explained regarding the Act's visibility protection program, "it is … premature to determine whether or not State SIPs … contain adequate provisions to prohibit emissions that interfere with measures in other States' SIPs," until those other states have adopted plans to implement the requirements of the Act for sources within their jurisdiction. *See* Memorandum from Director William T. Harnett, Air Quality Policy Division, OAQPS, "Guidance for State Implementation Plan (SIP) Submissions to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the 8-Hour Ozone and PM2.5 National Ambient Air Quality Standards" (August 15, 2006) at 9 ("§ 110(a)(2)(D) Guidance").

[28] This delay was the result of Congressional intervention. In 1998, reflecting the lack of existing $PM_{2.5}$ ambient monitoring data, Congress postponed the time by which EPA was required to designate areas of the country as either in attainment or nonattainment with the 1997 $PM_{2.5}$ NAAQS. Transportation Equity Act for the 21st Century (TEA-21), Pub. L. No. 105-178, § 6102(c)(1) (June 9, 1998). Under this law, designations were to be made within one year after the states had collected three years of ambient $PM_{2.5}$ monitoring data. Following collection of the necessary data, EPA promulgated $PM_{2.5}$ area designations on January 5, 2005, which included designating Madison County, Illinois, as nonattainment for the first time. 70 Fed. Reg. 944, 969 (Jan. 5, 2005).

[29] For attainment areas, EPA directed that state plans addressing § 110(a)(2) criteria other than § 110(a)(2)(D) be filed no later than October 2008. *See* § 110(a)(2)(D) Guidance (Aug. 15, 2006), at 2; *see also* 72 Fed. Reg. 20.586, 20,599-600 (Apr. 25, 2007). The initial attainment date for the 1997 $PM_{2.5}$ NAAQS was April 5, 2010. *Id*. at 20,600-3.

submits its § 110(a) SIP revision (according to EPA, those SIPs were due by October 2008), EPA is authorized to find that another state's SIP is "substantially inadequate" to address § 7410(a)(2)(D)(i)(I), and can issue a "SIP Call" to "require the contributing state to revise the plan as necessary to correct such inadequacies." *See* 42 U.S.C. § 7410(k)(5). This is the proper sequence under the statute and the one that EPA followed to address interstate transport in the "NOx SIP Call." There, EPA issued a SIP Call under § 110(k)(5) in 1998 only after the information about a state's "significant contribution" was available. *See Michigan v. EPA*, 213 F.3d 663, 669 (D.C. Cir. 2000). The statutory process requires notice and a timeline for the State to submit a revised SIP—it does not authorize an immediate FIP like the Final Transport Rule. The contrary approach taken by EPA in the Final Transport Rule, and EPA's interpretation of § 110(a)(1) underlying that approach, are contrary to the plain language of the statute.[30]

In addition, the plain language of the statute does not allow EPA to rely on a six-year old "finding of failure." Under § 110(i), SIPs can be revised only as provided in §§ 110(a)(3) and (c). 42 U.S.C. § 7410(i). Section 110(c) authorizes issuance of a FIP "*at any time within* two years" after a "finding of failure," subject to certain conditions. *Id*. § 7410(c) (emphasis added). "At any time within" a two year period does not mean "at any time after the expiration of" that period.

Regardless of the adequacy of a "finding of failure" at the time it is issued, if the inadequacy in a state's plan on which the finding was based ceases to exist, EPA's authority to promulgate a FIP would similarly expire. In this regard, state plans and EPA regulations change and, as a result, air quality improves. Under the plain language of the statute, a "finding of failure" does not confer on EPA the authority to issue a FIP for all time and regardless of changes in air quality or other circumstances. Congress, in the Clean Air Act, provided an

[30] EPA's generic April 2005 "finding of failure" is inadequate to start a "FIP clock" for the additional reason that EPA is required to identify Texas's "significant contribution" before it can require Texas to revise its SIP under § 110(k)(5) or otherwise. Section 110(a)(1)(H) only requires that SIPs "provide for revision of such plan—(i) from time to time *as may be necessary* to take account of revisions of such national primary or secondary ambient air quality standard or the availability of improved or more expeditious methods of attaining such standard[.]" 42 U.S.C. § 7410(a)(2)(H) (emphasis added). When EPA originally made its April 2005 "finding of failure," it did so in conjunction with CAIR, which specifically identified each covered state's "significant contribution." CAIR gave states eighteen months to revise their SIPs to address their identified "significant contribution" before a FIP would be put in place. *See* 70 Fed. Reg. 25,162, 25,263 (May 12, 2005). Accordingly, EPA explained that: "The EPA does not expect States to make SIP submissions establishing emissions controls for the purpose of addressing interstate transport without having adequate information available to them." *Id*. at 25,265 n.116. Here, EPA did not provide *any* information to Texas about its significant contribution until the Final Transport Rule was published simultaneously with its FIP in July 2011. This sequencing puts the cart before the horse and is contrary to the statutory requirement that states first address nonattainment within their own borders before it can be determined if upwind states are "significantly contributing" to downwind nonattainment.

explicit temporal limit on EPA's FIP authority. The explicit limitation on EPA's authority to promulgate a FIP to "any time within" a two year period recognizes that § 110(c) findings become stale, and that the primacy of states regarding air pollution control at its source would be nullified if a "finding of failure" provided EPA unlimited authority to override state planning decisions. This temporal limitation, of course, does not mean that EPA can never issue a FIP after the two year period expires; rather, it means that before a FIP can be issued, EPA must make a new finding of failure based on then-current information.

This temporal limitation is critical in the present situation, as the facts on the ground have changed dramatically since April 2005. If EPA had followed the statutory procedure here, it would have necessarily considered updated information regarding the Texas SIP (including Texas's $PM_{2.5}$ SIP submittal that EPA has found "administratively complete" in 2008) and the fact that Madison County, Illinois, has been found by EPA to be in attainment for the 1997 $PM_{2.5}$ NAAQS. This new information does not support issuance of a current finding of failure. For all of these reasons, EPA's April 2005 finding of failure cannot serve as a predicate for issuing a FIP to Texas as part of the Final Transport Rule, and EPA has no other basis under § 110 to do so.

IV. EPA's annual budgets for Texas give Texas and Texas EGUs no real choice in how to comply

The Final Transport Rule further usurps Texas's primary authority under the Clean Air Act by dictating how individual units must respond in order to comply. Although EPA maintains that it is not implementing a "direct control" strategy in the Final Transport Rule, that is in effect what EPA has done. This exceeds EPA's authority under the Clean Air Act. As the D.C. Circuit has held, §110 of the Act does "not permit the agency to require the state to pass legislation or issue regulations containing control measures of EPA's choosing." *Virginia v. EPA*, 108 F.3d 1397, 1408 (D.C. Cir. 1997). Even where EPA adopts a statewide budget or trading strategy purporting to give sources flexibility to meet the overall limits, the state must be given "real choice" in how to comply. *Michigan*, 213 F.3d at 687 ("Given the *Train* and *Virginia* precedent . . . the [NOx SIP Call] program's validity also depends on whether EPA's budgets allow the covered states real choice with regard to the control measure options available to them to meet the budget requirements."). This principle flows inexorably from the Clean Air Act's federal-state partnership, which gives states the "liberty to adopt whatever mix of emission limitations it deems best suited to its particular situation" "so long as the ultimate effect of a State's choice of emission limitations is compliance with the national standards for ambient air." *Train v. Natural Res. Def. Council, Inc.*, 421 U.S. 60, 79 (1975).

In *Michigan*, the D.C. Circuit found that the NOx SIP Call was consistent with *Virginia* because "EPA does not tell the states how to achieve SIP compliance. Rather … EPA merely provides the levels to be achieved." 213 F.3d at 687. The court observed: "States can choose from a myriad of … options," including various "mobile source" and "stationary source" compliance strategies. The NOx SIP Call, the court found, "allow[ed] states to focus reduction efforts based on local needs and preferences." *Id*. at 688.

Here, by contrast, EPA has told Texas (and other states) which sources to regulate—namely, large EGUs. This is uniquely constraining if compared to prior transport rules. For example, according to EPA, under CAIR, "through SIPs, the states could elect to allow boilers, combustion turbines, and other combustion devices to opt into CAIR trading programs." This is not allowed under the Final Transport Rule, which targets only large EGUs. FTR at 480. And, unlike the NOx SIP Call, "the Transport Rule does not allow states to expand the applicability to cover NOx SIP Call non-EGUs." *Id.* at 480-81. Clearly, the Final Transport Rule replaces state discretion regarding compliance options with EPA's policy preference for eliminating coal-fueled generation.

Furthermore, as a result of EPA's overly aggressive annual emissions budgets for Texas, the January 1, 2012 deadline for compliance, and changes that EPA has made to the trading program since the proposed rule, the Final Transport Rule does not even give Texas real choices for regulating Texas EGUs. In order to comply, Texas EGUs must reduce their SO_2 emissions by 47% and their NOx emissions by 8% beginning in just a matter of months. The reductions that EPA is requiring of Luminant—64% for SO_2 and 22% for NOx—are even more severe. The only way to meet these requirements is for individual units targeted by EPA to de-rate or shutdown. It is apparent that EPA's goal is to target and eliminate these individual Luminant units.[31] Since no Texas budget was provided from which to determine possible compliance scenarios, Luminant could not have raised the issues in this section during the public comment period.

EPA claims that "the Transport Rule does not impose unit level compliance strategies. While IPM may project a particular least cost compliance strategy, sources have the flexibility to comply with the state budgets through a variety of mechanisms (e.g., control installation, fuel switching, efficiency improvements, dispatch changes, allowance purchase, etc.)." Response to Comments at 2108. This claim by EPA is based on flawed data and assumptions; in truth, these "choices" do not exist in the real world.[32]

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[31] *See* Chris Roberts, *Texas blasts EPA's new ruling on pollution*, El Paso Times (July 18, 2011), *available at* http://www.elpasotimes.com/ci_18498051 (quoting Assistant Administrator Gina McCarthy: "Nearly half ... of the emissions of soot-forming sulfur dioxide covered by the rule are produced *by just three plants*, which, in turn account for only about one-tenth ... of the state's electricity generation. The balance of Texas power generation is already relatively clean and will not face a heavy compliance burden under this rule.") (emphasis added).

[32] In addition to being wrong, this is a new position that conflicts with EPA's prior assessment of feasibility in the proposed rule. EPA asserted in the proposed rule that its budgets for Group 2 states only require SO_2 reductions that could be made through "(1) the operation of existing scrubbers, (2) scrubbers that are expected to be built by 2010 and (3) the use of low sulfur coal." 75 Fed. Reg. at 45,290. With respect to NOx, EPA stated that its proposed NOx budgets for states "almost exclusively represents reductions from turning on SCR units" and "projected emissions rates for … new SCR units" expected by 2012. 75 Fed. Reg. at 45,290-01.

First, EPA's IPM modeling wrongly assumes that Luminant's Big Brown Units 1 & 2, Monticello Units 1 & 2, and Martin Lake Units 1, 2, & 3[33]—mouth-of-mine units that burn primarily Texas lignite—will switch to using 100% super-compliant Powder River Basin ("PRB") coal (coal with a sulfur content of 0.58 lbs./mmBtu or less).[34] These units are designed to burn lignite, a coal that has a lower heat-input value than most other coals. In order to switch to burning 100% of any grade of PBR, a coal with a significantly higher heat-input value than lignite, many of these units would require boiler component replacements (which cannot be physically accomplished by January 1, 2012), or else must be de-rated. EPA does not take this into account. Even if the boilers could immediately accommodate 100% PRB, all currently available super-compliant PRB coal is already under contract. In 2010, 142 million tons of super-compliant PRB were produced, and one producer owns approximately 75% of the market (Peabody). Exhibit 8. Luminant estimates that EPA's models predict national production of 197 million to 206 million tons of super-compliant PRB coal (at least 139% of the 2010 supply)—an unrealistic, if not implausible, modeling assumption. Clearly, the simple fuel switching projected by EPA does not reflect a real option.

Second, EPA's modeling uses incorrect removal efficiencies for the existing flue gas desulfurization units ("scrubbers") at five of Luminant's units. EPA assumes that the existing scrubbers at Martin Lake Units 1, 2, and 3, and Monticello Unit 3 can operate at a 95% removal efficiency, and Sandow Unit 4 at a 92% removal efficiency.[35] These *design* values used by EPA in its "remedy case" do not reflect the reported *actual* removal efficiency that can be presently achieved at these units. *See* Data from EIA Form 923 (2008) (Exhibit 9).[36] The actual removal

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However, EPA is now relying on "dispatch changes" and perhaps other undisclosed "mechanisms" at individual units to make its rule work. Response to Comments at 2108.

[33] These are seven of the eight Luminant units that currently use a blend of lignite and PRB.

[34] This assumption conflicts with EPA's claims elsewhere in the record that Texas sources can comply "without threatening . . . the continued operation of coal-burning units . . . that burn lignite from local mining operations" and "without altering Texas's current use of lignite." *Texas and the Final Cross-State Air Pollution Rule* at 1. EPA further states in the preamble to the Final Transport Rule that it "conducted sensitivity analysis that shows Texas can also achieve the required cost-effective emission reductions even while maintaining current levels of lignite consumption at affected EGUs." FTR at 337. Luminant has been unable to locate any unit-level data or analysis supporting these assertions, despite specifically requesting this information from EPA.

[35] *NEEDS Database v. 4.10*, Document EPA-HQ-OAR-2009-0491-4509.

[36] EPA inexplicably changed the inputs on scrubber efficiencies in the IPM modeling runs for the Final Transport Rule to use the reported data from the EIA Form 860 instead of the EIA Form 923, which it used in its proposed rule modeling runs. The Form 860 data reflects solely "design" values as opposed to actual performance. Thus, EPA has wrongly assumed much higher scrubber efficiencies than can actually be achieved. The design values were

efficiencies of these units are in the range of 65-75% as reported on EIA Form 923, not 95%. These existing scrubbers cannot appreciably improve their removal efficiency without retrofits (specifically, the installation of new wet stacks[37]) that require significant lead time to implement—at least two years for construction and up to five years total for planning, permitting, construction, and startup. This clearly is not possible by the January 1, 2012 compliance deadline.

Third, EPA's modeling assumes the operation in 2012 of three phantom scrubbers that do not even exist.[38]

Fourth, the dispatch changes that EPA is forecasting cannot occur by the January 1, 2012 compliance deadline, if at all. Unlike those serving other states, the ERCOT electric grid, which serves the majority of Texas, is a closed grid, meaning that it is not possible to import electricity generated in other states into the ERCOT region of Texas except on a very limited basis. EPA is assuming that gas-fueled capacity in Texas can fill the gaps in reduced generation from coal-fired EGUs, but its analysis includes well over 9,000 megawatts of gas-fueled capacity that is either retired or mothballed and thus cannot be brought online by January 1, 2012. For example, EPA assumes generation in 2012 from Luminant's North Lake gas-fueled plant. However, Luminant surrendered the air permit for that plant on December 15, 2009, and gutted the common control room, as shown in the picture attached as Exhibit 10. Clearly, this unit cannot be operated and dispatched. An even more egregious mistake is EPA's assumption that

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determined at the time of construction of the equipment, approximately thirty years ago in the case of Luminant's scrubbers. Thus, EPA effectively fails to take into account any decrease in removal efficiency occurring over the extended time in service. Furthermore, in its Form 860 filings, Luminant reported removal efficiencies for the percentage of flue gas that is run through the scrubber. Thus, to accurately reflect the actual removal efficiency, the removal percentage must be applied only to that percentage of the flue gas that flows through the scrubber (in most cases approximately 75% of the total flue gas, because the "dry" stacks at these facilities would be seriously degraded to the point of likely failure over time if all the flue gas were run through the scrubber).

[37] As a matter of engineering, Luminant's scrubbers cannot operate at the efficiencies assumed by EPA in the IPM modeling run. As explained above, the Form 860 data assumed application solely to that portion of the flue gas that runs through the scrubbers. At Luminant's units, the scrubbers and stacks were designed so that only a certain amount of the flue gas runs through the scrubbers. Running more of the flue gas through the scrubbers will necessitate installing a wet stack and additional fan capacity because the temperature and makeup of the flue gas that runs through the scrubber cannot be supported by the current dry stacks at Luminant's scrubbed facilities. If more flue gas is run through the scrubbers and fed into the dry stacks that currently exist, the resulting velocity and in-stack condensation would literally cause the stack to lean and, eventually, collapse.

[38] *NEEDS Database v. 4.10*, Document EPA-HQ-OAR-2009-0491-4509 (W. A. Parish Unit 5 and J.T. Deely Units 1 & 2).

Luminant's Collin Plant can be brought back to life. The Collin Plant ceased operations in 2003, was mothballed in 2004, and was *demolished* on July 1, 2011 (as the pictures attached as Exhibit 11 show). A complete listing of retired or mothballed gas-fueled units, which includes those units that EPA erroneously assumes will operate in 2012, is attached as Exhibit 12. Even if these units were physically capable of operating by January 1, 2012 (complete with plant staff and the necessary gas contracts), in a competitive wholesale market like ERCOT, mothballed capacity will only be brought back if market prices support operation of these higher marginal cost units. The mothballed units that EPA assumes will come online in 2012 are the highest marginal cost units to operate, and it is unlikely that market prices will result in the economic signal to reactivate these mothballed units. Further, EPA completely ignores NOx constraints on dispatching more gas plants in the state, particularly those that operate in the Houston and Dallas-Ft. Worth ozone nonattainment areas. Finally, EPA overestimates both the capacity and availability of wind generation. When calculating reserve margins, ERCOT counts wind generation—which, of course, is available only when the wind blows—at only 8.7 percent capacity to account for its intermittent nature.[39]

Fifth, allowance trading is not a viable option for Texas sources and Luminant in particular, especially given EPA's acceleration of the assurance provisions in the final rule from 2014 to 2012. Even with the variability "cushion" of 43,912 tons of SO_2 for Texas, there are insufficient allowances to cover the needed Texas generation without penalty. Assuming status quo operation, Luminant projects that it will be short approximately 160,000 SO_2 allowances in 2012. The sum of the positions for sources in Group 2 states that will have a "long" allowance position is only 59,000 allowances in 2012, meaning Luminant cannot just buy allowances to comply (unless it pays other sources to curtail or shut down). Also, the entirety of the Group 2 states, on a net position, are short, so it is unreasonable to expect that significant allowance trading would occur. Furthermore, sources in Texas would have to retire allowances above the 43,912 assurance level at a 3-1 basis under the penalty provisions in the final rule, which have been accelerated by EPA to 2012.[40]

The situation with regard to annual NOx trading is also strained. In 2012, the sum of the short positions of states in the annual NOx program is approximately 113,000 tons. Texas EGUs are short almost 17,000 tons (after accounting for owners that can leverage the allowances

[39] EPA's remedy modeling for Texas includes other errors of this nature that Luminant intends to raise in a reconsideration proceeding, such as overstating ERCOT's installed capacity and overstating co-generation capacity.

[40] EPA's acceleration of the assurance provisions to 2012 (and the 2012 deadline itself) is unnecessary to address attainment issues. As set out previously, Madison, Illinois, has been determined by EPA to be in attainment with the 1997 $PM_{2.5}$ NAAQS. Further, EPA can extend the attainment deadline for the 1997 $PM_{2.5}$ NAAQS until January 2015 based on "the availability and feasibility of pollution control measures." 42 U.S.C. § 7502(a)(2). Given the infeasibility of meeting the budgets set by EPA by the 2012 deadline, it would be arbitrary and capricious for EPA not to extend the deadline on this basis.

allocated to their operations outside of Texas). Although the sum of the positions of those states in the program that are long NOx (approximately 29,000 tons) is enough to cover the Texas short position, it cannot cover the entire short position of all states in the program. Thus, although a trading market may develop, it is not likely that the trading market will supply enough allowances to cover all states' short positions for 2012. Moreover, given the uncertainties with this new program and the fact that allowances may be banked indefinitely for compliance in future years, Luminant does not believe that even those owners with long positions will be willing to engage in any significant trading in 2012. Lastly, because the program essentially necessitates that generators make sure they have enough allowances in their accounts before they emit, units cannot take the chance that a trading market *might* develop to cover any excess emissions. This phenomenon will stifle trading until late in the year when generators are confident that they have enough allowances to cover their own 2012 emissions and therefore can sell any excess allowances. On the flip side, generators that are short will be forced to operate for most of the year without knowing how the trading market will develop. This will force generators that are short, including Luminant, to curtail operations to ensure compliance.

Sixth, EPA has effectively mandated that Texas achieve an additional 8% reduction of NOx emissions beginning on January 1, 2012—on top of the 21% reduction in Texas EGU NOx emissions made between 2005 and 2010. Exhibit 1. EPA claims that this can be achieved with "no new SCR [selective catalytic reduction] units" being installed. FTR at 424. EPA is wrong. Luminant's Big Brown, Monticello, and Martin Lake units have already installed the other available NOx control technologies that can be implemented on a relatively short time schedule.[41] For Luminant's fleet, the only option to achieve the necessary NOx reductions is to finalize the installation of at least two new SCRs at Martin Lake. The engineering, design, permitting, and construction timeline for such installation is expected to take at least four more years.[42]

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[41] Big Brown 1 & 2 and Monticello 1-3 are all equipped with over-fire air, low NOx burners, and selective non-catalytic reduction ("SNCR") technologies. Martin Lake 1-3 are equipped with over-fire air and low NOx burners. Luminant submitted a permit application for SCRs at Martin Lake in November, 2006. The Texas Commission on Environmental Quality ("TCEQ") issued a draft permit for comment in July, 2008. The Caddo Lake Coalition requested a hearing on the permit, and it is still pending. EPA does not account for such permit delays in its compliance assumptions.

[42] Further, EPA has overstated the removal efficiencies of existing SCRs. EPA's estimated NOx removal efficiencies for SCRs are not demonstrated efficiencies that the units can achieve on an ongoing basis. While EPA states it has applied a floor of 0.06 lbs./mmBtu, it did not do so in the remedy case for the following Texas coal units equipped with SCRs: JK Spruce Unit 2 (0.050 lbs./mmBtu); Oak Grove Unit 1 (0.050 lbs./mmBtu); Oak Grove Unit 2 (0.050 lbs./mmBtu); Sandow Unit 4 (0.049 lbs./mmBtu); W. A. Parish Unit 5 (0.056 lbs./mmBtu); W. A. Parish Unit 7 (0.043 lbs./mmBtu); and W. A. Parish Unit 8 (0.050 lbs./mmBtu). Sandow Unit 4 operates under a consent decree with a NOx limit of 0.08 lbs./mmBtu, and that limit, not some lower hypothetical one, should be used in EPA's modeling.

Thus, EPA has given Texas no real choice. To comply with the January 1, 2012 compliance date, certain Texas sources, targeted by EPA, will be required to shutdown or significantly curtail output. There is no "real choice with regard to the control measure options available to them to meet the budget requirements." *Michigan*, 213 F.3d at 687. The flexibility that EPA suggests is fictional, and the Texas annual program budgets are therefore unlawful.

Further, these and other errors with the modeling assumptions are of central relevance to the outcome of the rule in that they produce an overly stringent budget for Texas.[43] If adjustments were made to IPM to accurately reflect the unavailability of super-compliant coal for 2012; the demonstrated scrubber efficiencies at Luminant's units; the removal of three non-existent scrubbers; and a maximum PRB blend rate of 80% (the maximum blend possible without retrofits), the modeled output for Texas would be a significantly higher annual budget for SO_2 than 243,954 tons. With regard to NOx, if SCRs were assumed to be required for compliance, the cost per ton of NOx reductions would be well in excess of EPA's claimed cost of $500 per ton. Plainly, EPA's errors are consequential and, if corrected, would result in appropriate and substantial increases in Texas's annual budgets.

[43] Additional flaws and discrepancies in the "remedy case" assumptions for IPM are detailed in Exhibit 13.

Reasons EPA Should Stay the $PM_{2.5}$ FIP Compliance Deadline for Texas

In addition to convening a reconsideration proceeding as to Texas, Luminant requests that EPA stay and toll the effective date and compliance obligations of the $PM_{2.5}$ FIP as applied to Texas, pending its reconsideration and any judicial review. Both the APA and the Clean Air Act authorize an administrative stay. Under § 705 of the Administrative Procedure Act ("APA"), "[w]hen an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review." 5 U.S.C. § 705.[44] In addition, under the Clean Air Act, "the effectiveness of the rule may be stayed during reconsideration [] by the Administrator . . . for a period not to exceed three months." 42 U.S.C. § 7607(d)(7)(B).

Under the facts here, justice requires staying the effective date and compliance obligations of the $PM_{2.5}$ FIP as to Texas pending reconsideration and judicial review of the Texas-specific issues. One of the primary issues to be addressed on reconsideration and judicial review is EPA's failure to provide the public with sufficient opportunity to comment on aspects of the Final Transport Rule relating to Texas that differed significantly from the proposed rule, as discussed in detail above. These are material aspects of the rule. The Texas budgets, which were not developed with the benefit of public comment, set unrealistic and unsupported annual emissions limits for EGUs in the State of Texas, such that several of Luminant's units will be required to curtail operations and possibly shut down in a matter of months in order to meet them. In light of EPA's failure to give advanced notice of Texas's inclusion and disclose annual budgets for the state, sources in Texas have not been given the time to plan for the January 1, 2012 compliance deadline, in contrast to sources in other states for which EPA included proposed budgets in its August 2010 proposed rule.[45] EPA has also not solicited and received information, data, and comments regarding the final budgets for Texas. A stay is appropriate while EPA undertakes that statutorily-required effort through reconsideration.

Moreover, in light of the pressing compliance deadlines in the $PM_{2.5}$ FIP, sources in Texas, like Luminant, will need to begin to make major compliance investments and operational decisions immediately. These investments may not be reversible if the Texas emissions limits are in fact revised or if Texas is excluded from the rule following reconsideration and full evaluation of all relevant data. EPA has recently granted a stay of the effectiveness of its Industrial Boiler MACT rule under similar facts. *See* 76 Fed. Reg. 28,662 (May 18, 2011). As discussed above, to meet the newly-issued budget for Texas, sources must do more than simply implement "existing and planned SO_2 and NOx controls," as EPA assumed in setting the January 1, 2012 deadline for "Group 2" states and annual NOx program states. 75 Fed. Reg. at 45,301. The fact of the matter is that existing and planned controls are not sufficient to meet EPA's unrealistic new budgets for Texas. It is not a simple matter of switching fuels or "turning up"

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[44] Even if EPA denies Luminant's request for reconsideration, Luminant requests that EPA stay and toll the effective date and compliance obligations of the $PM_{2.5}$ FIP as applied to Texas pending judicial review in the U.S. Court of Appeals for the D.C. Circuit.

[45] Obviously, with no annual budgets proposed for Texas in the proposed rule, it was impracticable to raise this issue prior to issuance of the final rule.

installed scrubbers or SCRs or implementing NOx control strategies short of SCRs. Luminant's units will not be able to install the necessary additional pollution control equipment, nor will all of its units be able to conduct the work necessary to change coal types, by the January 1, 2012 compliance deadline or even the January 1, 2014 deadline, meaning the units would have to operate at significantly reduced output or possibly shut down. Accomplishing a fleet-wide fuel switch to only PRB coal by the January 1, 2012 deadline without significantly reducing the plants' electricity output is not possible. Nor is permitting, engineering, designing and construction of two new SCRs possible by either 2012 or 2014.

Staying the rule as to Texas is in the public interest. As a result of the Final Transport Rule, EGUs in Texas will be forced to cut production or shutdown in a matter of months, potentially resulting in the loss of jobs, loss of tax revenue, and collateral economic consequences, all of which will damage the small, rural communities that rely almost exclusively on these mines and plants for their economic livelihood. Given that EPA admits emissions from Texas sources may, at most, have only a marginal impact on downwind states (and in fact EPA has recently determined Madison County, Illinois, to be in attainment), imposing these adverse impacts and risks on Texas is neither advisable nor good public policy. After EPA considers public comment on the inclusion of Texas for its newly-alleged significant contribution to downwind $PM_{2.5}$ nonattainment and its new Texas budgets during reconsideration, Luminant is confident that EPA will exclude Texas or adjust the budget, making these economic and reliability disruptions unnecessary. A stay maintaining the status quo is thus appropriate.[46]

Electric reliability will also be put at risk, and reserve margins will be dangerously decreased without a stay. Because they will significantly and immediately reduce available generation capacity, EPA's new annual emissions budgets for Texas will without question threaten electric reliability in the state. EPA claimed in the proposed rule that its "emissions budgets [were] based on the reductions achievable at a particular cost per ton in that particular state, taking into account the need to ensure reliability of the electric generating system." 75 Fed. Reg. at 45,301. At the time EPA made this statement, it had not established annual emissions budgets for Texas, so it could not have taken into account the reliability of the electric generating system in Texas.

The record demonstrates that EPA has not adequately considered threats to electric reliability in Texas. EPA has vastly over-stated the amount of available capacity in ERCOT and understated Texas's reliance on coal-fueled generation. EPA's reliability analysis assumes 90,405 MW of capacity in ERCOT in 2014, with coal comprising 18,456 MW.[47] In contrast ERCOT stated in May 2011 that the available resources from 2014 were projected to be 75,967

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[46] As part of this stay, Luminant further requests that EPA stay its decision to remove CAIR allowances from individual accounts in EPA's Allowance Management System, which EPA has advised account holders it will do on October 14, 2011. EPA should leave CAIR allowances in individual accounts pending reconsideration and any judicial review.

[47] EPA-HQ-OAR-2009-0491-4399 at 5; EPA-HQ-OAR-2009-0491-4455 at 6.

MW with coal comprising 19,959 MW.[48] EPA's error is the cumulative result of overestimating a number of factors, including installed capacity, wind generation name plate capacity, co-generation capacity, and additional capacity that may come on-line by 2014.

With the recent disclosure of EPA's new budgets for Texas and its erroneous assumptions, it has become apparent that reliability problems will result despite the best efforts of generators like Luminant. The problems are compounded by other changes EPA made in the final rule. As OMB's report aptly stated:

> Further, accelerating the date the assurance provision becomes effective from 2014 (in the proposed rule) to 2012 (latest interagency draft), greatly changes compliance planning for 2012 and 2013. Such a substantial change occurring six month[s] prior to the effectiveness of the assurance provision leaves sources with few options to respond in a cost-effective manner, *increasing the likelihood of disrupting system reliability* if it becomes necessary to achieve compliance through derates and/or idling.[49]

These concerns have been confirmed by ERCOT. ERCOT has warned "that Texas could face a shortage of generation necessary to keep the lights on in Texas within a few years, if the EPA's Cross-State Rule is implemented as written."[50] Although ERCOT is continuing to evaluate the new rule, it has stated that the "initial implications are that the SO_2 requirements for Texas added at the last stage of the rule development will have a significant impact on coal generation, which provided 40 percent of the electricity consumed in ERCOT in 2010."[51]

ERCOT's concerns should not be taken lightly. ERCOT is an independent system operator charged by law to ensure the reliability of electricity in Texas. ERCOT manages the flow of electric power to 23 million Texas customers and has a targeted reserve margin of 13.75% to ensure electric reliability (EPA mistakenly based its assessment on a 12.5% reserve margin). Even without any temporary or permanent shutdown of units necessary to meet the January 1, 2012 deadline in the Final Transport Rule, ERCOT projects that this reserve margin will be threatened in coming years due to historic levels of demand in Texas.[52] Even without the lost generation as a result of the Final Transport Rule, summer reserve margins, which currently

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[48] ERCOT, *Report on the Capacity, Demand, and Reserves in the ERCOT, Region May 2011* (June 9, 2011 Revision 2), *available at* http://www.ercot.com/news/presentations/, at 7, 45.

[49] OMB Summary of Interagency Working Comments at 12 (emphasis added).

[50] *See* ERCOT, ERCOT CEO Statement Regarding EPA Cross-State Air Pollution Rule (July 19, 2011), *available at:* http://www.ercot.com/news/press_releases/2011/CEO_Statement_Regarding_EPA_Cross-State_Rule.

[51] *Id*.

[52] *See* Report on the Capacity, Demand, and Reserves in the ERCOT Region (May 2011 (June 10, 2011 Revision 2)), *available at* http://www.ercot.com/news/presentations/index#osp.

stand at 17.5%, are estimated to drop to 14.2% in 2013 and 11.1% in 2014.[53] These are conservative estimates, given that this summer has seen record system demand in ERCOT, with numerous record demand days in July and August—the peak thus far being 68,294 megawatts (MW).[54] *See* Exhibit 14. Luminant estimates that, with the load reductions and shutdowns that EPA's new emissions budgets for Texas will force, those margins will drop below target levels in 2013 and perhaps as early as 2012. This is practically assumed in EPA's base case modeling, which uses a maximum hourly load of 64,747 MW, approximately 3,200 MW or 5% short of the peak just seen in Texas.[55] Threatening electric reliability in this way clearly runs contrary to the public interest.[56] Based on these reliability concerns alone, EPA should convene a reconsideration proceeding and stay the rule as to Texas in order to take ERCOT's assessment of reliability into account and to correct errors in EPA's reliability assessment.[57]

In sum, for the reasons discussed above, Luminant requests that EPA convene a proceeding for reconsideration and provide the same procedural rights to owners of EGUs and other affected parties in Texas as were afforded those in states that are included in the Final Transport Rule, but were provided with proposed state emissions budgets. In light of (1) the impending unreasonable compliance deadline, (2) EPA's failure to provide Texas sources with advanced notice of inclusion and the resulting budgets to be imposed, (3) the substantial expenditures required to begin compliance activities, and (4) the social and economic harm that will shortly occur from de-rating or shutting down plants or mines, Luminant further requests that EPA stay the effectiveness of the rule and the compliance deadlines as to the State of Texas, pending its reconsideration and any judicial review of the Final Transport Rule, and extend the compliance deadlines as to Texas to reflect at least the stay period.

[53] *Id*. at 7.

[54] Exhibit 14 shows these peak demand days, as well as historical and projected peak demand in ERCOT.

[55] Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model, Document EPA-HQ-OAR-2009-0491-4385, *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2009-0491-4385 (posted July, 11, 2011).

[56] *See Sierra Club v. Ga. Power Co.*, 180 F.3d 1309, 1311 (11th Cir. 1999) ("[A] steady supply of electricity during the summer months, especially in the form of air conditioning to the elderly, hospitals and day care centers, is critical.").

[57] At an ERCOT Board meeting held July 19, 2011, ERCOT reported it had begun an analysis of the reliability problems posed by the Final Transport Rule and would report to the Public Utility Commission with an updated white paper. Luminant intends to supplement its request for reconsideration with that analysis when it is available.

Sincerely,

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List of Exhibits

Exhibit	Description
1	Texas SO_2 and NOx Emissions Data
2	Map: Granite City, Madison Co. Illinois to Mt. Pleasant, Titus Co., Texas
3	CSAPR PM2.5 Contributions for Texas on St. Louis (Illinois Slide)
4	Assessment of Local-Scale Emissions Inventory Development by State and Local Agencies
5	Memorandum of Understanding: U.S. Steel Corp., Granite City Works, and IEPA
6	Statement of Basis for a Planned Revision of the CAAPP Permit for U.S. Steel Corp.
7	State by State Contributions and Mandated Reductions
8	MSHA Mine Yearly Production Information: Antelope Coal Mine and North Antelope Rochelle Mine
9	Data from EIA Form 923
10	Photograph of Luminant's North Lake Plant- view of control room
11	Photographs of Luminant's Collin Plant- demolition
12	Public Utility Commission of Texas: Mothballed and Retired Generating Plants in Texas; New Electric Generating Plants in Texas Since 1995
13	CSAPR Issues of Concern
14	Historical and Projected ERCOT Peak Demand

Exhibit C

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NORTHERN STATES POWER COMPANY - MINNESOTA'S PETITION FOR RECONSIDERATION OF THE CROSS-STATE AIR POLLUTION RULE

Docket No. EPA-HQ-OAR-2009-0491

I. INTRODUCTION

Northern States Power Company - Minnesota ("NSPM"), a subsidiary of Xcel Energy Inc. ("Xcel Energy") respectfully submits this petition for reconsideration of the Cross-State Air Pollution Rule ("CSAPR"), 76 Fed. Reg. 48,208 (Aug. 8, 2011). NSPM requests that EPA reconsider its methodology for calculating allowance allocations for emissions of sulfur dioxide ("SO_2") and oxides of nitrogen ("NOx") for NSPM's High Bridge and Riverside plants, which were converted from coal to natural gas.

Reconsideration is appropriate here because EPA's final allocation methodology, which capped allocations to these plants based on their low post-conversion emissions, was presented for the first time in the final rule, denying NSPM opportunity to comment. The new approach unpredictably resulted in NSPM receiving far fewer allowances than it would have received under the previously proposed methodologies. EPA's allocation of allowances to NSPM's High Bridge and Riverside plants arbitrarily penalizes NSPM for reducing emissions at these plants before CSAPR was finalized.

In 2008 and 2009, NSPM replaced the existing coal-fired boilers at these two plants with natural gas combined-cycle units, resulting in massive emissions reductions at both power plants. In its calculation of allowances based on historical heat input, EPA utilized only the heat input after the conversion to natural gas, without providing NSPM credit for the higher historical heat input each plant had before the conversion. More important, EPA's methodology reduced the allocations to these plants to the level of emissions after the conversion, even though each plant had much higher actual emissions during EPA's 2003-2010 historical period. As a result, EPA's calculated allowance allocation is unfairly low because it does not recognize these proactive emission reduction efforts.

EPA did not explain or support this arbitrary decision. Indeed, it runs counter to the rationale EPA provides to justify its new allocation methodology:

> EPA believes that existing-unit allowance allocation under the Transport Rule should not generally advantage or disadvantage units based on the selection of fuels consumed or of pollution controls installed at a given unit in anticipation of either the Clean Air Interstate Rule or the Transport Rule, *i.e., fuel or control decisions taken from 2003 onward.* An approach that does not advantage or disadvantage units in this way avoids allocating in a way that would effectively penalize units that have already invested in cleaner fuels or other pollution reduction measures that will continue to deliver important emission reductions under this rulemaking. The approach selected in the final rule generally does not penalize such units and is thus generally fuel-neutral and control-neutral in its allocation determinations.

76 Fed. Reg. at 48,288 (emphasis added). NSPM agrees with EPA's statement that early reduction projects should not be penalized, but files this petition because EPA's final allocation method did penalize NSPM's High Bridge and Riverside projects contrary to EPA's expressed policy approach.

Xcel Energy and several other parties indicated in comments on the proposed rule that actions to convert plants from coal to natural gas should get the benefit of early action taken to reduce emissions. While EPA did not directly respond to Xcel Energy's comments on this issue, EPA stated in its response to comments that "units that are repowered (e.g. switched from coal fired to natural gas fired) and *still reporting as the same unit* would continue to receive the same allocation as prior to repowering." *See* Transport Rule Primary Response to Comments at 2649 (emphasis added). However, as explained below, the conversions done at the High Bridge and Riverside plants resulted in an administrative reassignment of unit numbers as NSPM worked with its state environmental agency to permit and implement the projects. EPA's decision to treat High Bridge and Riverside differently than other converted units merely because they did not retain the same unit number is arbitrary.

If EPA had indicated before the final rule that it was planning to reward early action by focusing on unit numbers, NSPM could have let EPA know why that was a flawed approach in relation to the Riverside and High Bridge projects. Instead, NSPM argued for early reduction credit but was not awarded that credit in the final rule because of EPA's final methodology for crediting early reductions. EPA therefore ended up penalizing NSPM's MERP project, which is a shining example of the types of early reduction actions that EPA says it encourages.

II. NSPM's METROPOLITAN EMISSION REDUCTION PROPOSAL

The conversion of the Riverside and High Bridge plants to natural gas was done as part of NSPM's Metropolitan Emission Reduction Proposal ("MERP"), which it submitted to the Minnesota

Pollution Control Agency ("MPCA") in July of 2002. *See* MPCA Review at 1.[1] The MERP was designed to achieve very substantial reductions in emissions at three of NSPM's power plants in the Minneapolis-St. Paul, Minnesota metropolitan area.

NSPM's MERP is exactly the kind of state initiative that EPA should reward through a more appropriate rulemaking design. The MERP was a voluntary project developed pursuant to state legislation that was supported by the state of Minnesota, most environmental organizations, electricity customers and, of course, NSPM. It was locally created. It occurred prior to and without the intervention of complicated federal rulemaking like CSAPR. Perhaps most importantly, because of these attributes, it achieved these important environmental goals at very reasonable cost to the people of Minnesota. As indicated in our comments on the original Transport Rule, these are exactly the kinds of state programs that EPA should recognize and reward. However, rather than rewarding NSPM and its customers for initiating and supporting these successful emission reduction projects, the final rule actually punishes the company for early reductions.

In its review of the MERP, MPCA concluded that the proposed projects would yield significant environmental and public health benefits for Minnesota. Before the projects, the High Bridge and Riverside plants, along with a third plant included in the MERP (the Allen S. King plant), represented almost half of all SO_2 released by electric utilities in Minnesota, and nearly a quarter of SO_2 emissions overall. MPCA Review at 4. The three plants were also responsible for 20% of the point source emissions of NOx in the state. *Id.* at 26. MPCA determined that the projects were not needed to comply with state or federal air quality standards, *id.* at 3, and conservatively calculated that the MERP would result in public health benefits equivalent to $200 to $500 million (in 2001 dollars). *Id.* at 4. This estimate did not account for several other important benefits of the MERP, including reduction of mercury emissions; reduced contribution to smog, regional haze, and acid deposition; and the reduced need for development of new energy generation sites and new transmission lines. *Id.* at 48.

NSPM is proud to report that the MERP was successful in achieving huge emission reductions: a 93% reduction in SO_2 emissions, a 91% reduction in NOx emissions, an 81% reduction in mercury emissions, a 55% reduction in particulate emissions, and a 21% reduction in carbon dioxide emissions. And this is just one project in NSPM's distinguished record of environmental leadership, exemplifying Xcel Energy's[2] commitment to substantially reducing emissions while at the same time reliably meeting customer demand for electricity at a reasonable cost.[3]

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[1] MPCA, Review of Xcel Energy's Metropolitan Emission Reduction Proposal, at http://www.pca.state.mn.us/index.php/view-document.html?gid=3992. Under the state statute that governed the MERP, the Minnesota Public Utilities Commission ultimately approved the MERP based in large part upon the MPCA's review.

[2] Xcel Energy is a major U.S. electricity and natural gas company with regulated operations in eight Western and Midwestern states (Minnesota, Wisconsin, North Dakota, South Dakota, Michigan, Colorado, Texas and New Mexico). Xcel Energy provides a comprehensive portfolio of energy-related products and services to 3.4 million electricity customers and 1.9 million natural gas customers. Xcel Energy's generating units are capable of producing over 16,400 MW of electricity, using a variety of fuel sources including coal, natural gas, oil, nuclear, renewables and hydropower.

[3] Xcel Energy is the nation's number one utility provider of wind energy, with over 3,100 MW of wind energy currently interconnected to its system. By 2015, the company plans to increase the wind capacity installed on its system to 5,000 MW. Xcel Energy also ranks fifth in the nation in terms of solar capacity and is a leader in energy efficiency. The company is leading the nation's utilities in reducing emissions; since 2010, pursuant to a state statute enacted in Colorado, Xcel Energy's subsidiary Public Service Company of Colorado is on a schedule

III. REQUEST FOR RECONSIDERATION

For the reasons set forth below, NSPM urges EPA to reconsider the allowance allocation methodology and to provide NSPM's High Bridge and Riverside plants allowances uncapped by the low level of post-conversion emissions.

A. EPA Reconsideration is Authorized Under Section 307(d)(7)(B).

Section 307(d)(7)(B) of the federal Clean Air Act ("CAA") provides for EPA's reconsideration of a CAA rule upon objection by a petitioner. *See* 42 U.S.C. § 7607(d)(7)(B). EPA *must* grant reconsideration when the petitioner:

> [C]an demonstrate to the Administrator that it was impracticable to raise [an] objection [during the period for public comment] or if the grounds for such objection arose after the period for public comment ... and if such objection is of central relevance to the outcome of the rule.

Id. In such a situation, reconsideration is mandatory, as the CAA commands that EPA "shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed." *Id.* (emphasis added). The reconsideration provision of Section 307(d)(7)(B) is applicable to the CSAPR rulemaking because the Administrator expressly determined that CSAPR is subject to the procedural provisions of CAA § 307(d). *See* 76 Fed. Reg. at 48,352.

B. EPA's Introduction of a New Emissions Allowance Allocation Methodology in the Final Rule, and its Impact on NSPM's Plants, Necessitates Reconsideration.

This petition unmistakably satisfies the standard for reconsideration. EPA did not provide an opportunity to comment on the methodology for allocation of emissions allowances presented in the final rule. Under the final rule, EPA allocates SO_2 and NOx allowances to units based on their historic heat input, capped by the unit's historic emissions. *See* 76 Fed. Reg. at 48,288. This methodology was not presented in the proposed rule or any of the subsequently issued notices of data availability ("NODAs"). It was, therefore, "impracticable to raise [an] objection" to the allowance allocation methodology during the public comment period, and reconsideration is necessary. 42 U.S.C. § 7607(d)(7)(B).

EPA claims that the final allocation methodology was a logical outgrowth of the options presented in the proposed rule and the subsequent NODAs. *See* 76 Fed. Reg. at 48,288. NSPM disagrees and is confident that a reviewing court would reject EPA's position. The D.C. Circuit has stated that, "[g]iven the strictures of notice-and-comment rulemaking, an agency's proposed rule and its final rule may differ only insofar as the latter is a 'logical outgrowth' of the former." *Envtl. Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005) (stating that "[t]he test is whether a new round of notice and comment would provide the first opportunity for interested parties to offer comments that could persuade the agency to modify its rule"). A "final rule is a 'logical outgrowth' of a proposed rule only if interested parties should have anticipated that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *Id.* at 998. An agency's notice of proposed rulemaking must provide sufficient detail for interested parties to comment meaningfully. *Horsehead Resource Dev. Co. v. Browner*, 16 F.3d 1246, 1268 (D.C. Cir. 1994). Consequently, courts will strike down agency action that seeks to "use the rulemaking process to pull a surprise switcheroo on regulated entities." *Envtl. Integrity Project*, 425 F.3d at 998.

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to substantially re-work its Colorado generation portfolio, which will result in an 84% reduction in SO_2 and an 89% reduction in NOx emissions in a non-CSAPR state.

Here, EPA admits that the final methodology was not discussed in the proposed rule or the subsequent NODAs. EPA explains that the final methodology is Option 2, which was proposed in the NODA issued on January 7, 2011, but "modified in response to public comments." 76 Fed. Reg. at 48,288. EPA explains that it abandoned the "reasonable upper-bound capacity utilization factor and a well-controlled emission rate" factors that were proposed in Option 2. *Id.* In their place, EPA introduced a brand new factor: an allowance cap based on a unit's historic emissions, which was not discussed in any of the prior proposals. NSPM could not have anticipated that EPA would adopt into its methodology a factor that had not been considered in any of the three previous proposals.

NSPM received significantly fewer allowances under the final allocation methodology than it would have received under either of the methodologies proposed in the NODA:

SO_2 Allocations						
Plant	**Option 1 Allocation**	**Final Allocation**	**Percent Reduction**	**Option 2 Allocation**	**Final Allocation**	**Percent Reduction**
High Bridge	503	2	99.6%	522	2	99.6%
Riverside	281	2	99.3%	292	2	99.3%

NOx Allocations						
Plant	**Option 1 Allocation**	**Final Allocation**	**Percent Reduction**	**Option 2 Allocation**	**Final Allocation**	**Percent Reduction**
High Bridge	440	50	88.6%	446	50	88.8%
Riverside	246	82	66.7%	250	82	67.2%

In all cases, NSPM's final CSAPR allocation for these plants was capped at actual, post-conversion historic emissions, whereas at proposal the plants were provided significantly more allowances based on historic heat input (albeit heat input after the plants were converted to natural gas). NSPM could not have anticipated that the final rule would result in such extreme reductions in allowances, and was denied an opportunity to comment on the method of calculating these allowances.

C. The Exclusion of Historic Heat Input and Emissions Data for NSPM's Plants Prior to Their Conversion to Natural Gas is Arbitrary and Inappropriate.

The final allowance allocations to NSPM's four High Bridge and Riverside units were reduced by EPA's arbitrary and irrational decision to exclude from its allowance calculations historic heat input and emissions data that predated these plants' natural gas conversion projects.

In 2008, as part of the MERP, NSPM replaced the existing coal-fired units at the High Bridge plant with two combustion turbine units that are connected to a Heat Recovery Steam Generator to further reduce heat rate and emissions from the plant (a combined cycle unit). The units were given new unit numbers 7 and 8, but were built on the same site as the replaced coal units (units 5 and 6). In 2009, NSPM changed the Riverside plant by installing two combustion turbine units (replacing the existing coal units) that are connected to a Heat Recovery Steam Generator to further reduce heat rate and emissions from the plant.. The combustion turbine units utilize the steam turbine from units 6 and 7. As part of the project, the coal-fired boilers from units 6, 7 and 8 ceased to operate and the combustion turbine units were renamed units 9 and 10. In both cases, NSPM's customers paid the costs associated with early action and achieved significant reductions in emissions Unfortunately, the allowance allocation methodology utilized by EPA in the final rule failed to give credit to these plants for these significant emission reductions.

EPA's methodology first calculates a unit's allowance allocation based on the average of the three highest non-zero annual heat inputs between 2006 and 2010 and then caps that allocation so that it is no higher than the highest actual emissions between 2003 and 2010. In applying this methodology to the High Bridge and Riverside plants, EPA utilized only data from those plants after they were converted to natural gas, even though they operated as coal plants during part of the time period EPA used to develop the allowance allocations. Thus, EPA used no historic heat input data from High Bridge during 2006 and 2007, but only heat inputs for 2008 through 2010. Similarly, for Riverside, EPA used no historic heat input data for 2006 through 2008, but only heat input for 2009 and 2010. Even with the use of heat input only after the plants were converted to natural gas, the initial heat input-based allocation for SO_2 in the final rule were 527 for High Bridge and 480 for Riverside. The initial heat-input based allocation for NOx were 371 for High Bridge and 338 for Riverside. However, because the actual, post-conversion emissions for both plants were extremely low as a result of the conversion to natural gas, the emissions were capped at the actual, post-conversion emissions, as set forth in the following table:

Allowance Allocation Calculation per EPA						
Plant	**Initial Heat Input Based 2012 and 2014 SO_2 Allocation (tons)**	**Initial Heat Input Based 2012 and 2014 Annual NOx Allocation (tons)**	**Annual SO_2 Maximum Historic Baseline (tons)**	**Annual NOx Maximum Historic Baseline (tons)**	**Final SO_2 Allocation (tons)**	**Final NOx Allocation (tons)**
High Bridge	527	371	2	50	2	50
Riverside	480	338	2	82	2	82

As a result, the Riverside and High Bridge plants received very few allowances, thus receiving no credit for the emission reductions achieved through the MERP. In contrast, had EPA used the heat input and annual emissions from the historical period prior to their conversion, the units would have received significantly more allowances. The following charts provide actual heat input and emissions data for the relevant period.

Actual Heat Input During Baseline Period			
Plant	**Year**	**Actual Annual Heat Input (mmBTU)[4,5]**	**Average of the 3 Highest Values**
High Bridge Pre-Conversion	2006	17,441,117	14,176,024
	2007	10,910,930	

[4] Pre-conversion heat input obtained from EPA Clean Air Markets web site, Monitoring Location Level emissions.

High Bridge Post-Conversion	2008	3,609,480	5,240,692
	2009	5,406,075	
	2010	6,706,522	
Riverside Pre-Conversion	2006	21,999,174	22,866,584
	2007	27,145,984	
	2008	19,454,595	
Riverside Post-Conversion	2009	2,561,200	4,795,977
	2010	7,030,753	

Actual Annual SO_2 and NOx Emissions During Baseline Period

Plant	Year	Actual Annual SO_2 Emissions (tons)[5]	Actual Annual NOx Emissions (tons)[5]
High Bridge Pre-Conversion	2003	**3,965***	5,955
	2004	3,806	**6,070**
	2005	3,463	5,837
	2006	3,406	5,063
	2007	2,096	3,188
High Bridge Post-Conversion	2008	1	29
	2009	2	43
	2010	2	50
Riverside Pre-Conversion	2003	**14,670**	**13,344**
	2004	12,361	12,117
	2005	12,573	12,716
	2006	10,057	9,853
	2007	12,972	12,339
	2008	10,492	9,677

[5] SO_2 mass, NOx mass, and Post-conversion heat input obtained from EPA Clean Air Markets web site, Unit Level Emissions.

Riverside Post-Conversion	2009	22[6]	44[6]
	2010	2	82

* Bolded data represent the highest emission values during the baseline period.

EPA should recalculate the allowances for the Riverside and High Bridge plants using the pre-conversion heat input and emissions in the table above. This would appropriately recognize the massive emission reductions undertaken by these plants during the emissions baseline period. If EPA for some reason determines that it should use the post-conversion heat input of the plants, EPA should at the very least award the plants with the initial heat input-based allocations uncapped by post-conversion emissions.[7]

Xcel Energy and several other parties indicated in comments on the proposed rule that actions to convert plants from coal to natural gas should get the benefit of early action taken to reduce emissions. While EPA did not directly respond to Xcel Energy's comments on this issue, EPA stated in its response to comments that "units that are repowered (e.g. switched from coal fired to natural gas fired) and *still reporting as the same unit* would continue to receive the same allocation as prior to repowering." *See* Transport Rule Primary Response to Comments at 2649 (emphasis added). However, as discussed above, the conversions done at the High Bridge and Riverside plants resulted in the assignment of different unit numbers for administrative reasons. EPA's decision to treat High Bridge and Riverside differently than other converted units merely because they did not retain the same unit number is arbitrary.

It is also bad policy. Under CSAPR, NSPM would have received a much larger allocation had it left the Riverside and High Bridge plants uncontrolled on coal. EPA's approach to allocation in this rulemaking gives no credit to coal plant retirement as early action. It is a powerful disincentive to other utilities considering whether to pursue their own proactive emission reduction programs.

EPA criticized its initial proposal's emission-based allocation methodology because it "would disadvantage one of two otherwise identical existing units if it invested in emission reductions in anticipation of the Clean Air Interstate Rule or this final Transport Rule." EPA concludes that "[t]he heat-input allocation methodology selected for the final Transport Rule does not have this flaw." 76 Fed. Reg. at 48,289.

To the contrary, the final methodology *does* have this flaw. With respect to the High Bridge and Riverside plants, the final methodology does exactly what EPA says it does not: it penalizes NSPM for investing in emission reductions at its coal-fired power plants by awarding more allowances to identical coal-fired plants that did not undergo similar projects.

In sum, the final allocation methodology is arbitrary and unfair to companies like NSPM that invested in early emission reduction efforts. It also is unfair to the ratepayers who help finance such projects. This outcome is based on EPA's arbitrary and unreasonable decision to exclude pre-conversion baseline data from the allocation calculations for converted plants whose units did not retain the same unit number designation. EPA should reconsider this arbitrary and inappropriate outcome and allocate additional allowances to the Riverside and High Bridge plants by including all data on historic heat input

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6 These values include 21.2 tons of SO_2 and 8.1 tons of NOx contributed by Riverside Unit 8 in 2009.

7 NSPM notes that this request does not impact the overall allowance allocation EPA developed for the state of Minnesota, but does impact how it is allocated within the state.

and actual emissions from these plants for all years in the baseline periods that EPA used to develop its allowance allocations. At the very least, EPA should utilize the past actual emissions of the plants to ensure that the initial heat-input based allocations are not diminished as a result of the plants' low, post-conversion emissions.

IV. CONCLUSION

For the reasons discussed above, NSPM urges EPA to reconsider the allowance allocation methodology set forth in CSAPR as applied to NSPM's High Bridge and Riverside plants, and allocate additional allowances to them as described above.

Dated: October 5, 2011

On Behalf of Northern States Power Company - Minnesota

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SOUTHWESTERN PUBLIC SERVICE COMPANY'S
SUPPLEMENTAL PETITION FOR RECONSIDERATION AND REQUEST FOR STAY OF THE CROSS-STATE AIR POLLUTION RULE

Docket No. EPA-HQ-OAR-2009-0491

I. INTRODUCTION

Southwestern Public Service Company ("SPS"), a subsidiary of Xcel Energy, Inc. ("Xcel Energy"), respectfully submits this Supplemental Petition for Reconsideration and Request for Stay of the Cross-State Air Pollution Rule ("CSAPR"). 76 Fed. Reg. 48,208 (Aug. 8, 2011). This Supplemental Petition follows SPS's Initial Petition for Reconsideration ("Initial Petition"), which SPS submitted to EPA on August 23, 2011.

In CSAPR, EPA has created a new rule that places SPS's customers—the people of West Texas and Eastern New Mexico—at great economic and personal risk. Without notice or opportunity for public comment, EPA unexpectedly subjected the State of Texas to the full regulatory reach of CSAPR and then compounded the impact of this decision by imposing an utterly impracticable requirement that Texas sources comply with the rule by January 1, 2012, less than five months after its publication.

The imposition of CSAPR's new and draconian requirements on such an unreasonable schedule provides SPS with insufficient time to implement nearly all of the available control technology options. In the initial years of the CSAPR program (and especially in 2012), it leaves SPS with no choice but to run its electric system in a way it was never designed to run: to reduce dramatically the operation of its base load coal plants and commit to run its aging peaking and intermediate gas plants around the clock. As discussed in SPS's Initial Petition, this "system flip" operating plan would, at a minimum, result in a huge increase in customer energy costs—currently estimated to be as high as $200 to $250 million in 2012. That abrupt cost increase comes at a time when the U.S. economy is still reeling from the protracted economic slowdown.

More importantly, as also recognized by other utilities, reliability regions and states, this type of "system flip" also exposes SPS's customers to a substantially increased risk of electric system reliability problems. It could lead to blackouts. Utility systems are carefully planned and built with multiple redundancies to greatly reduce the possibility and scope of system emergencies or failures. These redundancies include, among other things, standby peaking power plants, power import capabilities, and power purchase options. These redundancies are reinforced by careful transmission system and network design. Under CSAPR, however, SPS would be forced to run the electric system in a way that cannibalizes these redundancies; SPS would need them to serve daily load and would not be able to reserve them for system emergencies.

In its Initial Petition, SPS outlined the severe nature of the "system flip" that would be required to meet the huge emission reductions that EPA has mandated for 2012. For that Initial Petition, SPS modeled a potential compliance scenario on an average load year, and pointed out that this analysis was far from a worst case scenario. In this Supplemental Petition, SPS discusses its additional analysis showing the impact of CSAPR on its ability to meet system load in more challenging years. In any year, system conditions are likely to deviate from the average. The SPS system has often experienced years where wind production is lower, temperature is hotter, or an unexpected plant or equipment outage occurs for an extended period of time. In fact, 2011 was such a year. This past summer, West Texas and Eastern New Mexico experienced record heat, and SPS's electricity was a lifeline for our customers. The loss of this electricity, even for a short period, would be devastating, and the CSAPR requirements unreasonably increase the potential for this risk to be realized.

CSAPR's short compliance deadline for Texas apparently grows from EPA's confidence in the outputs from its power dispatch computer models. In reliance on these models, EPA believes that SPS can comply with CSAPR merely by purchasing emission allowances placed on the market by yet-unrealized emission reductions at other utilities. While models may be useful as planning tools, they are no substitute for good judgment and common sense. They cannot predict the future with the certainty that EPA is apparently ascribing to them. In effect, EPA is asking SPS to be its agent for a high stakes environmental policy experiment, one that tests whether a constrained and complicated emissions trading program can, in just five months, deliver both substantial emission reductions and reliable, cost effective power. If this experiment fails, it is the people of West Texas and Eastern New Mexico that will pay the price.

II. SUMMARY

In its Initial Petition, SPS emphasized the unreasonableness of EPA's belated decision to include Texas in the annual reduction programs for sulfur dioxide ("SO_2") and oxides of nitrogen ("NO_x") emissions under CSAPR and its unreasonably immediate compliance deadline of 2012. SPS filed its Initial Petition with the utmost urgency given the belated addition of Texas and the rapidly approaching compliance deadlines. In that Initial Petition, SPS noted that a second petition for reconsideration containing additional technical detail would likely follow once SPS had additional time to analyze the voluminous information placed into the docket with EPA's issuance of the final rule. This Supplemental Petition contains additional information that warrants reconsideration and stay of CSAPR as follows.

First, since submitting the Initial Petition, SPS has completed additional modeling to assess the impacts of 2012 CSAPR compliance on its system under conditions that deviate from the average. In the Initial Petition, SPS's model assumed average load, average outage rates and no extraordinary conditions. Even under average conditions, the model showed that an unprecedented "system flip" would be required for SPS to comply with CSAPR. In the new modeling presented in this Supplemental Petition, SPS has modeled two additional scenarios that vary from historical average conditions: a high-load scenario and an extended-outage scenario. Both scenarios assume that allowances will not be available from outside the SPS system for the reasons stated in the Initial Petition and confirmed in this Supplemental Petition. Under these very realistic scenarios, the SPS models cannot fully reconcile compliance with CSAPR with reliable system operations.

Second, SPS has identified critical errors and flaws in EPA's IPM modeling, which form the basis for the state emissions budgets. In particular, the IPM modeling is overly-simplistic in failing to account for constraints in intra-regional and inter-regional transmission capabilities, which in turn leads the model to predict impossible dispatch scenarios in the SPS system.

Finally, SPS has noted its additional concerns—beyond those already identified in the Initial Petition—with several legal flaws in CSAPR. SPS, like other parties that have filed petitions with EPA and the Court of Appeals, believes these flaws place the rule on highly questionable legal ground and warrant reconsideration. EPA erred in finding a linkage between Texas sources and $PM_{2.5}$ nonattainment in Madison County, Illinois, given that EPA recently found Madison County to be attaining the 1997 $PM_{2.5}$ national ambient air quality standard ("NAAQS"). EPA also used a flawed method for setting state budgets, which is unrelated to the state's actual contribution to downwind nonattainment and inconsistent with judicial direction in *North Carolina v. EPA,* 531 F.3d 896 (D.C. Cir. 2008), *modified on rehearing*, 550 F.3d 1176 (D.C. Cir. 2008). Because these issues have been addressed by other petitioners, SPS has not given them lengthy discussion in this Supplemental Petition. However, SPS strongly believes that these issues warrant reconsideration of CSAPR.

In sum, this Supplemental Petition provides additional support for SPS's Initial Petition urging reconsideration and stay of the CSAPR's application to Texas. SPS re-asserts the arguments and evidence presented in its Initial Petition here, as well as its request for stay. For ease of reference, SPS attaches its Initial Petition as Attachment A to this Supplemental Petition.

III. REQUESTS FOR RECONSIDERATION AND REQUESTS FOR STAY

A. EPA Reconsideration and Stay Is Authorized Under Section 307(d)(7)(B).

Section 307(d)(7)(B) of the federal Clean Air Act ("CAA") provides for EPA's reconsideration of a CAA rule upon objection by a petitioner. *See* 42 U.S.C. § 7607(d)(7)(B). EPA *must* grant reconsideration when the petitioner:

> [C]an demonstrate to the Administrator that it was impracticable to raise [an] objection [during the period for public comment] or if the grounds for such objection arose after the period for public comment … and if such objection is of central relevance to the outcome of the rule.

Id. In such a situation, reconsideration is mandatory, as the CAA commands that EPA "*shall* convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed." *Id.* (emphasis added). The reconsideration provision of Section 307(d)(7)(B) is applicable to the CSAPR rulemaking because the Administrator expressly determined that CSAPR is subject to the procedural provisions of CAA § 307(d). *See* 76 Fed. Reg. at 48,352.

The CAA authorizes EPA to stay the effectiveness of the rule for up to three months during reconsideration. *See* 42 U.S.C. § 7607(d)(7)(B). The Administrative Procedure Act ("APA") further authorizes EPA to stay the effectiveness of a rule indefinitely during reconsideration. Under the APA, "[w]hen an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review." 5 U.S.C. § 705. EPA has applied this standard to CAA actions. *See, e.g.,* Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Aggregation, 75 Fed. Reg. 27,643 (May 18, 2010). The standard for such an administrative stay is different from the standard for a stay used by the courts because a judicial stay requires a demonstration of irreparable harm. This is clear from the text of the APA:

> When an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review. On such conditions as may be required and to the extent necessary to prevent irreparable injury, the reviewing court ... may issue all necessary and appropriate process to postpone the effective date of an agency action or to preserve status or rights pending conclusion of the review proceedings.

Id.

Thus, the APA deliberately contrasts what is required for an administrative stay—"justice so requires"—and a judicial stay—"conditions as may be required" and "irreparable harm." Similarly, CAA Section 307(d)(7)(B) authorizes an administrative stay, but does not premise that stay on a finding of irreparable injury. Such differences must be given effect,[1] so

[1] "[W]here Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion." *Russello v. United States,* 464 U.S. 16, 23 (1983) (quotation marks and citation omitted; alteration in original).

there is no irreparable harm requirement for an administrative stay. Given the potential impact of these regulations on SPS and other affected source operators in Texas, "justice so requires" that EPA stay the new provisions of the final rule and take other necessary and appropriate steps to defer the compliance deadlines and other provisions of the final rule until the outcome of the reconsideration process.

B. Further analysis by SPS Only Confirms that EPA's Decision to Impose CSAPR's Requirements on Texas Sources Beginning January 1, 2012 Must be Stayed and Reconsidered.

1. Background: SPS's Initial Petition detailed the errors in the late addition of Texas to CSAPR and the unreasonableness of the 2012 compliance deadline.

In its Initial Petition, SPS demonstrated that EPA's decision to add Texas sources to the rule only at its final promulgation cannot be a "logical outgrowth" of the proposal. *See* Initial Petition at 6–8. SPS and other Texas utilities were provided with notice and the opportunity to comment only on a preliminary, speculative question of whether Texas should be included based on hypothetical future emission increases in Texas that might be caused if the rule were implemented in other states but not in Texas. However, EPA did *not* provide notice or request comments on its new reason for inclusion of Texas in the annual program. In fact, EPA now concedes that comments on the only Texas-related issue that it raised at proposal are "no longer relevant." U.S. EPA, Transport Rule Primary Response to Comments at 563 (July 2011). As SPS explained in its Initial Petition, this procedural defect necessitates reconsideration in any instance, but it is particularly unreasonable here, where regulated utilities in Texas were given only five months from publication in the *Federal Register* to comply. *See* Initial Petition at 9–10.

SPS's Initial Petition explained the unreasonable nature of the 2012 compliance deadline as it applies to the SPS system. *See id.* at 8–14. SPS must assume for planning purposes that there will be inadequate quantities of allowances available for purchase. *See id.* at 11. There is simply no time to see how the allowance market will develop given the compliance deadline. Even if some companies are able to reduce emissions sufficiently to generate allowances, it cannot be known whether they will elect to keep their allowances as a hedge for their own future year compliance obligations. Similarly, as described in the Initial Petition for Reconsideration and in more detail below, because of the serious constraints on SPS's ability to import power into West Texas, SPS will not be able to import sufficient power into the SPS service territory to supplant generation from its units to comply with CSAPR. *See id.* at 12.

SPS explained that its first modeling efforts showed that the only way for the company to meet its SO_2 reduction requirements is through a radical "system flip" of its generation portfolio. *See* Initial Petition at 12-14. This would require the company to employ its gas-fired peaking units as though they were base load units, with concomitant reduction in utilization of its coal units. In this scenario, SPS's total generation from coal would decrease from 46% to 26% and total generation from natural gas would increase from 37% to 53% (including a significant increase in generation from natural gas-fired units in New Mexico). *Id.* at 12. SPS further explained that neither the SPS generation system nor the SPS transmission system was designed in anticipation of this type of dispatch scenario, and that SPS's modeling of the system flip indicates that SPS may incur up to $200 million to $250 million of additional costs in 2012 under this scenario. *Id.* at 13. These increased costs would stem from added costs to switch from coal to natural gas, additional costs for purchase power, higher transmission costs, higher costs for natural gas due to increased demand, and potential liquidated damages on coal rail contracts. *Id.*

2. The "system flip" that would be required to comply with CSAPR starting in 2012 dramatically and inappropriately increases the potential for system reliability problems

SPS's concerns about the 2012 compliance deadline have only intensified as the company has continued to analyze its ability to meet the year-2012 CSAPR allocations given to its units. In this section, SPS will explain the deviations of actual conditions from the "average year" that SPS used to model its compliance scenarios and discuss the multiple stresses on its system that compliance with CSAPR starting in 2012 would cause. It should be obvious that there is no guarantee of an "average year" and that things may go wrong when SPS attempts to operate its system in a manner inconsistent with its design. Given the importance of electric system reliability, the care with which it is managed, and the margin for error that must be present to assure continuous system operation, SPS believes that the considerable stress placed on its system by the radical changes needed to comply with CSAPR will present an unacceptable risk of system failure.

a. Under scenarios that deviate somewhat from historical average conditions, SPS faces increased risk of reliability problems.

Since preparing the Initial Petition, SPS has completed more extensive modeling of a wider range of scenarios, in addition to the average year scenario presented in the Initial Petition. The average year scenario demonstrated that SPS might be able to comply with CSAPR in 2012 by undertaking a system flip, but at enormous expense, unacceptable reliability risk and little margin for error. SPS modeled two additional scenarios to highlight the increased risks posed to the SPS system in attempting 2012 CSAPR compliance in a non-average year. The two scenarios discussed here are: (1) a high-load scenario that looks at a year similar to 2011 (with a significantly hotter-than-average summer and concomitant increased load); and (2) an extended-outage scenario that looks at how the SPS system would cope with a two-month unexpected outage at a key natural gas plant while trying to maintain the system flip.

To analyze and validate these scenarios, SPS used the ProSym[2] production cost model to develop the total system fuel and purchased power expense. ProSym is a least-cost, probabilistic commit-and-dispatch model that simulates SPS generation resources, SPS contractual assets, and electric markets to meet SPS's load requirements. The ProSym simulation inputs include variables such as the SPS system load forecast, generating unit characteristics and operating parameters, committed purchases and sales, fuel commodity prices, transmission area constraints, and electric market prices.

The ProSym modeling confirms that a radical system flip is the only means by which SPS might meet its customer demand with the CSAPR allowances granted to SPS Texas units.[3]

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[2] ProSym is a registered trademark of Ventyx, an ABB company.

[3] As SPS explained in its Initial Petition (at 11), and in Section III.B.2.d, *infra*, the company must plan to meet the requirements of CSAPR without purchasing allowances. Without an established market and without further indication of how other Texas utilities will meet the obligations of CSAPR, SPS simply cannot assume that it will be able to acquire at a reasonable cost any allowances that it might need to comply.

Under the two newly modeled scenarios that deviate somewhat from historical average conditions (high-load and extended-outage), SPS could not get the ProSym model to find a system operating scenario that would meet expected electric demand while complying with CSAPR in 2012 using its allocated allowances.

i. High-Load Model

One need look no further than this past summer to see that that SPS cannot simply limit its planning to normal summers and winters. Year-to-date, the company is experiencing 2.7% higher loads due to the abnormally hot summer weather. In June, July and August of this year, loads were 5.9%, 5.0% and 6.6% higher than normal respectively.

The ProSym analysis using above-average loads similar to those experienced in 2011 shows that in order to comply with the CSAPR emissions allocations, SPS would will be forced, as part of the "system flip," to rely heavily on natural gas combustion turbines at the Cunningham Station in New Mexico. However, the run time hours of this plant are significantly restricted by its Title V permit. As a result of this run-time constraint, these units cannot provide sufficient additional generation to satisfy SPS customer load during the high-load scenario modeled. Similarly, the modeling of the high-load scenario shows that SPS would need to rely heavily on the recently constructed Jones 3 unit located in Texas. This unit also is subject to air permit limits on total run hours and mass emissions. Thus, the company will not be able to rely on Jones 3 to provide the extra generation SPS would need during an above-average load year while meeting the CSAPR emission limits.[4]

As a result of these constraints and others, the ProSym analysis could not find a solution that allows SPS to meet the required load and comply with CSAPR. If the weather in 2012 is anything similar to that which SPS is experiencing this year, SPS's modeling did not find a way for SPS to both meet its increased electric load and comply with CSAPR in 2012 using only its allocated allowances.

ii. Extended-Outage Scenario

SPS also used ProSym to model the impacts on its system of compliance with CSAPR using allocated allowances in 2012 while experiencing an unplanned, extended outage at a key generating plant. Such an outage, while always possible, may become more likely once the system is flipped and operated in an untested configuration. To evaluate this scenario, SPS ran a simulation in which a two-month outage was assumed at one of its large (> 500 MW) generating plants that is crucial to the system in terms of serving load and attempting to comply with CSAPR allocations. The modeled plant has a low heat rate and low NO_x emission rate and therefore is expected to be heavily relied upon on in order to meet any CSAPR scenario. If this modeled plant had an unexpected or planned outage of two months duration, the modeling indicates that SPS would be unable to comply with CSAPR in 2012 using existing allocations while meeting other system load serving requirements. Furthermore, as in the high-load scenario, this scenario results in existing units running at capacity factors well in excess of historical levels. This level of operation could potentially result in higher forced outage rates and

[4] SPS notes that changes to air emission permit limits, particularly relaxation of operational limitations, often require extensive permit reviews that normally take well over a year to complete. EPA did not give sufficient allowance to the time needed to make these kinds of changes when deciding to impose CSAPR limits in 2012.

increased maintenance time for key units that could further exacerbate system operations and compliance with CSAPR allocations.

iii. Implications of the modeled scenarios

In sum, in the newly modeled high-load and extended-outage scenarios, SPS has not been able to model a dispatch plan that will allow it to comply with CSAPR in 2012 using only its allocated allowances. This is true even using the expensive and unprecedented "system flip" operating plan described in our Initial Petition. Despite increasing 2012 customer energy costs by up to $200 to $250 million, that operating plan is not an assured path to both compliance and reliability in these scenarios.

The modeled scenarios assume that the SPS units that are covered by CSAPR will not have any additional control equipment installed to assist with the 2012 compliance period.[5] This is the assumption underlying EPA's IPM modeling for 2012. SPS is doing everything possible to accelerate installation of pollution control equipment to aid in meeting the requirements of CSAPR. However, a set of low-NO_x burners for the company's Tolk Station is the only equipment that is likely to be installed in time to provide emissions reductions during 2012.[6] SPS is currently seeking the permits necessary to authorize the installation of a low-NO_x burner on Tolk Unit 1. SPS is making every effort to have this equipment permitted, installed, and operational on Tolk Unit 1 by the end of February 2012. The company also is working urgently to procure equipment and engineering services for the installation of low-NO_x burners on Tolk Unit 2, with the hopes that the equipment could be permitted, installed and operational by the summer of 2012. While this equipment installation will help reduce SPS's allowance shortfall for NO_x by a small amount, it will not come close to eliminating SPS's overall NO_x allowance shortfall under CSAPR. SPS has not identified viable options to install SO_2 emission control equipment in 2012.

b. By requiring substantially increased operation of natural gas plants and cycling of coal plants, CSAPR imposes unacceptable reliability risk on the SPS electric system.

In attempting to provide sufficient generation to meet system load while complying with CSAPR emission limitations in 2012, the SPS system would be strained by the need to run natural gas-fueled generators in both Texas and New Mexico as base load plants, despite the fact that these units are older units that are simply not intended for base load operation. Additionally, SPS's base load coal plants operate best in a steady-state condition as opposed to the sporadic and variable operation that would be required to meet CSAPR's emission reduction requirements. These unconventional operating conditions would place SPS and its service area under a significant reliability risk, which is only intensified in the high-load or extended-outage scenarios that SPS modeled.

The chart below indicates the impact of the modeled high-load scenario—similar to the load experienced in West Texas and Eastern New Mexico in 2011—on the capacity factors for the gas-fired generators.

[5] Neither the Tolk nor Harrington Stations have any SO_2 control equipment. SPS has minimized the SO_2 emissions from all five units at these plants through the exclusive use of low-sulfur Powder River Basin coal since the units were first constructed.

[6] All three units at Harrington Station, SPS's other coal-fired plant, already have low-NO_x burners.

Plant and Unit	Normal Capacity Factor	Capacity Factor Under CSAPR High-Load Scenario
Cunningham 1	31%	61%
Cunningham 2	34%	68%
Cunningham 3	6%	62%
Cunningham 4	3%	44%
Jones 3	10%	18%
Maddox 1	24%	58%

As the chart demonstrates, compared to normal pre-CSAPR operations, the gas-fired Cunningham Station's Units 1, 2, 3 and 4 would need to run at capacity factors 30%, 34%, 56% and 41% higher on an absolute value basis, respectively. On a relative basis, the capacity factors for these units would at least double and, for older units, would increase approximately ten fold. Cunningham Unit 1 has been in operation for 54 years and Unit 2 has been in operation for 46 years. In fact, Unit 1 normally stays in cold reserve shut down during winter months under normal operations. Likewise, Cunningham Unit 3 is a gas combustion turbine that is not intended to run at capacity factor levels in excess of 50% on a year-in-year-out basis as would be necessitated by CSAPR. These older plants were not built for this kind of base load operations, and the reliability risks associated with having to do so are substantial.

To serve SPS load under this high-load scenario, the gas-fired units at SPS's Plant X in Lamb County, Texas also would have to run at significantly increased capacity factors. Plant X has four gas-fired units that were built in 1951, 1953, 1955, and 1964. Compared to normal operations, Units X3 and X4 would have to run 21% more to serve high load as part of SPS's effort to meet the CSAPR imposed emissions limits. However, SPS has not equipped Plant X for base load operations and does not have time to do so in time for 2012 compliance. Even during the 1980s, the units were not operated very often, and SPS has not upgraded this aging equipment since then because the units have always been run at lower capacity factors. Operating these units under the system flip scenario would bring with it a serious risk to reliability.[7]

Maddox Station, a gas-fired boiler with steam turbine built in 1966 and sited near Hobbs, New Mexico, also would operate well outside its normal operating parameters under the high-load scenario for compliance with CSAPR in 2012. Currently Maddox runs as a load follower with lower capacity factors. Under the high-load scenario, with the system flip necessitated by CSAPR, Maddox Unit 1 would have to run at a capacity factor 34% higher than normal on an absolute basis, which is roughly 1.5 times the unit's normal capacity factor. This would expose the Maddox Station, like the Cunningham Station and Plant X, to unacceptable reliability risk.

SPS's Jones Station, near Lubbock, Texas houses three gas-fired units. Units 1 and 2, which are gas-fired boilers with steam turbines, were built in 1971 and 1974. The third unit, a gas turbine, was put into service 2011. During the 1980s, Units 1 and 2 were cycled daily, and

[7] Further, these older units have a poor heat rate and are less efficient than the coal units. In fact, EPA's IPM Remedy Case modeling forecasts that Plant X will not be operated at all.

the units have suffered fatigue damage. Under the CSAPR high-load scenario, the Jones 1 and 2 units would have to be run at a capacity factor 17-20% higher than normal. This scenario, like the others described above, may not be achievable on a unit that has had years of thermal cycling.

Finally, reliability concerns associated with a system flip are not limited to the gas-fired peaking units. Tolk Station has two coal fired units that were put in service in 1982 and 1985, and Harrington Station has three coal fired units that were installed in 1976, 1978 and 1980. Because of the low cost of their fuel, SPS has operated these units as base load facilities at a relatively constant generation level. Under the modeled scenario, in order to comply with CSAPR, neither the Tolk Station nor Harrington Station units will operate as base load units but instead will operate as load followers. Coal plants that load-follow must cycle up and down frequently, and, if they were originally designed to be baseload facilities, they can be expected to face substantially greater operations problems and maintenance costs. SPS will likely see similar reliability problems with Tolk and Harrington under the CSAPR system flip operating scenarios.

Moreover, under this scenario, the emissions reductions that SPS's coal-fired plants have recently realized may not be sustainable. SPS recently purchased software designed to reduce NO_x emissions on all five coal units. This unique tuning tool makes incremental changes to the boiler and has lowered NO_x emissions from SPS's coal-fired units. However, the tuning tool works best during the steady state conditions of the furnace, and it usually takes over an hour to stabilize the controls and reach the best efficiency of the furnace. In the CSAPR operating scenarios, cycling the coal plants would severely undercut the effectiveness of the tuning tool. In addition, coal mill operations also will be difficult under CSAPR dispatch requirements. With frequent, unpredictable changes in load, the mills will be forced to cycle, and this will in turn upset the boiler conditions and cause additional maintenance that must be managed to comply with CSAPR. In other words, the CSAPR system flip will likely result in increased emission rate and reduced reliability of the SPS coal plants.

c. SPS's ability to import electricity from other reliability regions is limited, will not be sufficient under the modeled scenarios and poses increased reliability risk when used as contemplated in SPS's CSAPR compliance scenarios.

The real-world risks associated with a system flip are not confined to the company's generation operations. The system flip, as necessitated by CSAPR, would force SPS to rely on import power at much higher levels than the company does today, thereby limiting the amount of import capacity in reserve and largely consuming an important reliability safeguard. SPS's ability to import power is limited by constraints in its transmission system.[8] As described in the Initial Petition, SPS is in the Southwest Power Pool, which is part of the electric reliability grid that runs from the East Coast to the Great Plains. SPS's system is located between the western reliability grid (that runs to the West Coast) and the grid that is managed by the Electric Reliability Committee of Texas. SPS can import power into its system from outside the Southwest Power Pool only through direct current interconnections ("DC Ties"). As indicated in

[8] This section describes the real-world stresses to SPS's transmission system and attendant risks to reliability brought on by compliance with CSAPR. Separately, the IPM model's failure to fully and accurately address important inter-regional and intra-regional transmission constraints renders that model's output deeply flawed. This results in significant errors in Texas's emissions budgets. *See* Section III.C.2, *infra*.

the map attached hereto as Attachment B, these two ties are the Lamar DC Tie connecting the SPS system to the Public Service Company of Colorado ("PSCo") system and the Blackwater DC Tie to the Public Service Company of New Mexico ("PNM") system.

The SPS analysis of CSAPR compliance scenarios indicates that SPS would have to import as much power as possible into the SPS service territory over the only two available DC Ties. The Lamar DC Tie would need to deliver power 90% of the time, well above the current normal level of 36%. The Blackwater DC Tie would need to deliver power 83% of the time, compared to 68% under current normal operations. This excessive level of power import would be required even under the average-load scenario presented in the Initial Petition. SPS has never before accomplished this level of power transmission across these DC ties for an extended period of time. Thus, SPS cannot rely on additional import capability to meet the higher loads of an above-average year modeled in the high-load scenario.

SPS has purchased 139 MWs of conditional firm transmission between Albuquerque, New Mexico and the Blackwater DC Tie from PNM. This purchase allows SPS to gain access to electricity markets at Four Corners. However, the conditional firm restriction means PNM must make best efforts to support flows of electricity, including by running more expensive and inefficient older generation to maintain the required stability. Should this redispatch not achieve the required stability, then PNM must curtail the flows to maintain its own system first. By forcing SPS to increase its reliance on the Blackwater tie, the CSAPR system flip scenario would expose SPS to the reliability risks of PNM's system. If a PNM plant trips offline during a required redispatch period, PNM may curtail SPS's electricity schedules. During 2011, PNM required redistpach every day from June through September, and multiple days outside of this period. Through September 1, 2011, the path was unavailable for use 18 days, or about 7% of the time. Increasing the reliance on this path increases the likelihood of curtailment, and reduces the effectiveness of this path as a reliable means to redispatch the SPS system to comply with CSAPR.

SPS's second DC tie comes out of Lamar, Colorado. Here, SPS may call upon up to 200 MWs from SPS's sister company PSCo. Typically the tie is reliable, but it is behind the SPP-SPS Flow Gate. The SPP-SPS Flow Gate is a constrained point in the transmission system that limits SPS's access to energy from the Eastern Interconnect to less than 724 MWs.[9] SPS currently has rights to 410 MWs of firm transmission capacity across this constrained point. Another entity within the SPS Balancing Authority owns 100 MWs, thus leaving 214 MW remaining. The remaining capacity is inaccessible except on a non-firm basis. The ties allow economic non-firm energy to flow at times, but system stability continuously manages the limits. These flows are unreliable and SPS cannot count on these as a dependable long-term option to redispatch its system.

[9] In contrast, EPA's IPM modeling documentation incorrectly suggests that SPS might have access to up to 2814 MW of import capacity from bordering regions, as described more fully in Section III.C.2 of this Supplemental Petition, *infra*.

d. Because of the very short time period before SPS must begin compliance with CSAPR, SPS must undertake its compliance planning for 2012 without assuming that sufficient allowances will become available.

In the modeled scenarios, SPS assumed that significant emissions allowances will not be available for purchase, and SPS's experience to date indicates that SPS must continue to make this assumption. The allowance market for the four programs created by CSPAR, including the three programs that cover SPS, are in very early development. So far, there is not enough liquidity for SPS to assume that it will be able to purchase adequate allowance to operate normally. As of September 26, 2011, there had only been a handful of trades in the over-the-counter allowance markets for Group 1 SO_2 (not relevant to SPS because Texas is a Group 2 state) and for annual and seasonal NO_x. No trades have been posted for Group 2 SO_2. The volumes have also been very small, with the trades all under 1,000 tons and most at 100 tons.

Given this sluggishness in the allowance markets, SPS started working to identify and originate allowance transactions with possible counterparts through bilateral contracts. Unfortunately, the entities contacted so far by SPS have indicated that they are still uncertain of their available allowance positions and may prefer to bank 2012 vintage allowances, or they would prefer a swap of allowances. With the very short allowance position that SPS is in, this is not an option for SPS, and SPS has not yet identified a realistic partner for trading or purchasing allowances.

By imposing the CSAPR compliance obligation starting in 2012, EPA allowed too little time for the Group 2 SO_2 allowance market to fully develop, particularly considering the late inclusion of Texas in the Group 2 SO_2 control program under CSAPR. CSAPR's structure of imposing state-level emissions budgets (with a corresponding 47% reduction in SO_2 emissons from Texas EGUs) depends on a fundamental assumption that a robust emissions allowance market will quickly develop with sufficient amounts of relatively inexpensive allowances. As SPS first noted in its Initial Petition, this assumption does not account for the likelihood that sources may hold extra 2012 allowances as a hedge against compliance obligations in future years, particularly since 2012 is the first operational year of the new CSAPR program. In addition, the CSAPR Group 2 states present a much more limited trading zone than any of the other cap-and-trade programs EPA has implemented to date, leaving significant concerns about the viability of the emissions trading markets for Group 2 states.[10] Given this considerable uncertainty about the allowance markets, SPS cannot begin operations in 2012 based on the assumption that allowances will become available later in the year, because this could leave SPS out of compliance with CSAPR.

e. Conclusion

SPS takes seriously its obligations to provide reliable electricity to its customers while at the same time meeting all applicable environmental compliance obligations. SPS will take such actions as necessary to meet those dual obligations. However, SPS's modeling demonstrates that

[10] In its Petition for Reconsideration, the State of Texas noted that, based on emissions projections in EPA's revised lignite sensitivity analysis, if each of the Group 2 states made exactly the SO_2 reductions available at $500/ton, and if all available Group 2 allowances are sold only to Texas sources, the state would still be short 23,994 allowances. See Texas Petition at 15, n.11.

2012 CSAPR compliance likely will be extremely costly and cannot be accomplished without a significant and unacceptable risk to reliability. SPS is not alone in expressing concerns regarding the impact of CSAPR on electric reliability. In addition to statements by other transmission organizations, significant reliability concerns have been raised by the Southwest Power Pool ("SPP") in a letter to EPA dated September 20, 2011, which is included as Attachment C. According to SPP:

> The result of SPP's reliability assessment of the EPA's CSAPR IPM generation dispatch indicates serious, negative implications to the reliable operation of the electric grid in the SPP region raising the possibility of rolling blackouts or cascading outages that would likely have significant impacts on human health, public safety and commercial activity within SPP.
>
> ***
>
> The time period between finalization of the CSAPR and its effective date is too short to allow SPP and its members/registered entities to appreciate the effects of the rule and to take actions to ensure reliability.

SPS agrees with SPP's statements and believes they are consistent with the issues raised in this Supplemental Petition and the Initial Petition submitted by SPS.

C. EPA's IPM Modeling and Allocation Methodology Contains Flaws and Errors Affecting SPS Sources.

Optimally managing a generation portfolio to maximize efficiency and ensure system reliability presents a highly complex problem that requires SPS to consider the age and capabilities of its generating assets as well as many transmission constraints present within the system. The IPM modeling on which EPA relied to develop the state emissions budgets does not account for these fundamental limitations to operations faced by SPS and other utilities, and in many instances the IPM results are plainly at odds with actual data. As a result, the statewide budgets—which are drawn from the IPM modeling—are arbitrary and capricious. SPS has identified several significant errors and omissions that EPA must at a minimum correct on reconsideration, with the appropriate updates to the Texas statewide emissions budget. More fundamentally, however, the flaws in the IPM modeling leave serious doubts about the accuracy of that modeling and its ability to forecast the complex problem of ensuring reliability on a region-wide basis. This uncertainty presents yet another reason why EPA should stay the effectiveness of CSAPR as it applies to Texas sources during reconsideration.

1. IPM Remedy Case modeling of the SPS system is contrary to SPS's only compliance option.

At the outset, SPS notes that the dispatch profile of the SPS generating assets, as modeled in the EPA's IPM remedy case, is completely different than the "system flip" dispatch profile that SPS has identified though its modeling as the only way to approach compliance with CSAPR's year-2012 allowances. The IPM remedy case calls for SPS to operate its coal-fired units at relatively high capacity factors, while barely running its older, gas-fired units at all.[11] As described in SPS's Initial Petition for Reconsideration, and also in the discussion above, this is not possible if SPS is to meet the CSAPR budgets with extremely limited import capacity and without purchasing allowances for which no market has yet been established. SPS recognizes that the IPM remedy case has been developed with the assumption that SPS will be able to purchase the necessary allowances, but, as noted previously, SPS simply cannot assume that it will be able to purchase the necessary allowances if it is to ensure reliable service throughout the year 2012.

2. The failure to properly model intra- and inter-region transmission constraints, and other local reliability issues, renders the IPM model and the state budgets derived therefrom deeply flawed.

As explained above, SPS's ability to import power is limited by significant inter-regional and intra-regional constraints within its transmission system. SPS must manage these constraints as it seeks to ensure system reliability, and SPS has detailed in Section III.B.2.c, *supra*, the extent to which its efforts to comply with CSAPR are limited by transmission considerations. As a separate but related issue, EPA's IPM modeling fails to adequately account for the real-word transmission constraints that system operators such as SPS must confront. This flawed IPM modeling leads to significant errors in Texas's emissions budgets. SPS has identified four significant flaws in the IPM modeling as it relates to transmission.

First, the IPM modeling of transmission flow levels appears to be based on transfer capability information based on 2004 NERC Summer and Winter Assessments.[12] These assessments provide some indication of inter-regional flow capability at the current time, but the use of 2004 data would of course not account for any changes to the various transmission networks in the seven years since 2004. Given the sophistication and the importance of accurate transmission data to CSAPR's dispatch modeling, SPS believes that EPA should have relied on more current inter-regional transfer information as the basis for any transmission analysis on which it bases important rule design decisions.

Second, the use of the inter-regional transfer capabilities comes with a hidden assumption that makes the results of the IPM modeling questionable. The transfer capabilities are determined assuming a base dispatch of generation, both fossil and non-fossil generation, in the various regions. Should the results from EPA's study effort indicate that reductions in fossil based generation were required, then the transfer capability numbers used in the IPM modeling may not be valid; they do not incorporate the transmission impacts arising from the reduction in fossil generation resulting from CSAPR. To properly assess the transmission feasibility of such generation reductions, EPA should request updated regional transfer capabilities with modified

[11] Capacity factors calculated from generation levels specified in the IPM Remedy Case parsed files, *available at* http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html, indicate that the coal-fired units at the SPS Tolk and Harrington Stations are modeled to operate at capacity factors of approximately 78% and 82% respectively. In contrast, SPS's gas-fired units are modeled to operate at very low capacity factors: Nichols Units 1 and 2, and Jones Units 1 and 2 are modeled to operate at approximately 13% capacity. Moore County Unit 3, Nichols Unit 3, and Plant X's four units are not forecasted to operate at all.

[12] *See* U.S. EPA, Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model at 3-9 (Aug. 2010) ("Table 3-5 shows the annual joint limits to the transmission capabilities between model regions, which are identical for the firm (capacity) and non-firm (energy) transfers. The joint limits were developed from the 2004 NERC Summer Assessment and 2004 NERC Winter Assessment.")

generation dispatches from the appropriate regional entities and then determine if there is sufficient inter-regional capability to make the overall program work. Until such studies are completed and confirm the existence of adequate regional transfer capability, EPA should not have relied on such capabilities in promulgating the rule.

Third, the IPM modeling assumes that electricity may freely flow within a modeled region, here Southwest Power Pool South ("SPP-S"). In other words, *it is assumed that SPS can access any available generation within SPP-S without any transmission constraints.* EPA's analysis of reliability in the IPM model "assumes that adequate transmission capacity exists to deliver any resources located in, or transferred to, the region."[13] For the same reasons stated above, any generation re-dispatch to limit fossil-based output may change inter-area transfer capability (inside SPP-S) and any transfer capability assumed by EPA may not be feasible. This approach virtually guarantees that smaller limitations of the local transmission network will be completely missed, since there is no detailed representation of them in the IPM model. For example, the IPM should have accounted for local transmission constraints which force the operation of certain SPS units for electric reliability or voltage support. These units include units at Plant X, which were modeled to operate at a 0% capacity factor in the IPM remedy case.

A related fourth problem is that the IPM modeling assumes an amount of import power that is available to be brought into the region and assumes that, once in the region, that power can freely flow where it is needed. This error is a result of the IPM model's incorrect assumption of unlimited intra-region transmission. Consequentially, the IPM model underestimates the demand on units within the SPS system, and assumes access to external power that does not truly exist. The result is a deeply flawed model result and an unsupportable state emissions budget.

The IPM model's failure to address intra-regional transmission constraints is problematic in all reliability regions, and it leaves a particularly important problem with the model's treatment of the SPS system. As explained above, the SPP-SPS Flow Gate is a constrained point in the transmission system that limits SPS's access to energy from the rest of the Eastern Interconnect to less than 724 MWs. In contrast, EPA's IPM modeling documentation suggests that SPS, as it sits within SPP-S, might have access to up to 2814 MW of import capacity from bordering regions:

- 735 MW from Entergy to SPP-S;
- 400 MW AZ/NM to SPP-S;
- 979 MW from ERCOT to SPP-S; and
- 700 MW from SPP-North into SPP-S.

In making that assumption, EPA has ignored the SPP-SPS Flow Gate and overstated the amount of available import capacity that SPP may access by a factor of roughly four. In practice, these assumptions will cause the IPM model to overlook or discount the extent to which SPS must rely on its own generating units rather than importing power from other regions. These generation demands, which are brought on by transmission constraints, should be reflected in the model by detailed transmission system analysis, which would include modeling of the proposed fossil

[13] Resource Adequacy and Reliability in the IPM Projections for the Transport Rule TSD at 2.

dispatch changes in conjunction with current transmission system models, as developed by the appropriate regional entities. SPS recommends that EPA consult with the various Regional Transmission Organizations and Independent System Operators to verify the model's consistency with real-world transmission constraints and associated system-dispatch requirements.[14]

These numerous flaws in the IPM model result in an unsupportable state emissions budget. These flaws present yet another reason why EPA should stay the effectiveness of CSAPR as it applies to Texas sources during reconsideration. On reconsideration, EPA should re-run the IPM model and adjust the state budgets accordingly. In doing so, the model should draw on more current inter-regional transmission data, and the model should better account for inter-regional and intra-regional transmission constraints. The inter-regional data should take into account the prospective generation dispatch that would likely result from the state budgets. Specifically, with regard to SPS, a revision of the IPM model should account for the transmission limitations that constrain SPS's ability to import power into its relatively isolated system. In particular, the model should consider the SPP-SPS Flow Gate, which ultimately limits the amount of power that SPS can import from the larger Eastern Interconnect to 724 MWs.

D. CSAPR Contains Fatal Legal Errors.

SPS also joins other petitioners, including the State of Texas and Luminant Generation Company LLC, in emphasizing that EPA must consider and stay the Texas-specific components of CSAPR to address the serious legal deficiencies in the rule as it relates to Texas. As SPS noted in its Initial Petition, and as other petitioners have made clear, SPS and other affected members of the regulated community were afforded no opportunity to comment on these and other flaws in the rule affecting Texas because of the unreasonably limited nature of EPA's proposal as it related to Texas. *See* Initial Petition at 6-8. SPS recognizes that the State of Texas and Luminant have elucidated these procedural and legal flaws in the CSAPR in petitions for reconsideration already before EPA. For that reason, SPS has emphasized the unreasonable consequences of CSAPR to SPS and its customers in this Supplemental Petition. Nevertheless, SPS joins these other petitions in emphasizing that EPA must reconsider the inclusion of Texas in CSAPR as well as the rule's method for determining statewide emissions budgets.

1. The inclusion of Texas in the CSAPR program is unsupported by the good neighbor provision of the CAA and is arbitrary and capricious.

EPA included Texas in the CSAPR SO_2 program based on the state's "linkage" to Madison County, Illinois, as modeled by EPA. *See* 76 Fed. Reg. at 48,241, Table V.D-2. At proposal, EPA indicated that it had not found Texas sources to be making a significant contribution to nonattainment in a downwind state. As a result, SPS and other Texas sources had no opportunity to comment on EPA's current finding of linkage to Madison County, Illinois. However, as both Luminant and Texas have explained in detail, Madison County is now attaining the 1997 $PM_{2.5}$ NAAQS. *See* Luminant Petition at 16-19, Texas Petition at 7-10 (citing 76 Fed. Reg. 29,652(May 23, 2011)). EPA has confirmed this with its May 23, 2011 final

[14] Further, for purposes of consistency and accuracy, any assumed flow capabilities across known boundaries, or defined flow gates, should be compared to the current values in the NERC Book of Flowgates.

"action determining that the Saint Louis fine particle ($PM_{2.5}$) . . . has attained the 1997 National Ambient Air Quality Standard." 76 Fed. Reg. at 29,652.

Further, as Luminant and Texas have also explained, a close review of the local conditions in Madison County, Illinois show that at the Granite City monitor—the sole monitor in the sole county responsible for Texas's eleventh-hour inclusion in CSAPR—a local steel mill was the primary contributor to past nonattainment measurements. At the same time four other monitors in Madison County modeled attainment, raising obvious questions about how Texas sources might be significantly contributing to nonattainment at one monitor in Madison County, but not the other four. *See* Luminant Petition at 17-18; Texas Petition at 9. Given the local conditions surrounding the Granite City monitor, and given EPA's finding that Madison County, Illinois is *attaining* the 1997 $PM_{2.5}$ NAAQS there is no tangible indication that Texas sources actually "contribute significantly" to $PM_{2.5}$ nonttatainment in Madison County or any other out-of-state county. The unsupportable "linkage" between Texas sources and the Madison County, Illinois shows flaws in EPA's modeling-only approach in CSAPR.

2. The emissions budgets in CSAPR are unsupported by the good neighbor provision of the CAA and are arbitrary and capricious.

EPA's method for developing the emissions budgets in CSAPR is unsupported by the Clean Air Act because it is divorced from what is actually necessary to prevent regulated sources from "contribut[ing] significantly" to nonattainment in downwind states. In *North Carolina v. EPA*, the D.C. Circuit urged that the Clean Air Act's good neighbor provision "gives EPA no authority to force an upwind state to share the burden of reducing other upwind states' emissions. Each state must eliminate its own significant contribution to downwind pollution." 531 F.3d at 921. Despite this clear direction from the court, EPA arbitrarily required statewide emission reduction obligations based primarily on cost-effectiveness even where the reductions have not been shown to be necessary to meet air quality objectives. In fact, CSAPR mandates reductions from Texas sources far beyond what is necessary to address the contribution to nonattainment EPA models predicted occur at most at only one of several monitors in one county in one downwind state. Texas sources will be forced to reduce SO_2 emissions by 47% beginning just five months after the rule's publication. Luminant noted that Texas reductions under CSAPR at $500/ton will drop the contributions by the state's sources to 16% below the significance level defined by EPA, while other states will continue to significantly continue to nonattainment in downwind states. Luminant Petition at 21. These reductions mandated in Texas are therefore well beyond what is allowable under the good neighbor provision as it was interpreted by the D.C. Circuit in *North Carolina*.

IV. CONCLUSION

For the reasons discussed above, and for the reasons discussed in SPS's Initial Petition for Reconsideration, SPS urges EPA to reconsider the applicability of CSAPR's $PM_{2.5}$ program to Texas sources as well as the related 2012 compliance deadline. SPS further requests that EPA immediately stay the effectiveness of that program as it applies to Texas sources during reconsideration and proceedings for judicial review.

Dated: October 5, 2011

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On Behalf of Southwestern Public Service Company

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Exhibit E

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Joe Hantz
Manager
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October 1, 2010

Air and Radiation Docket and Information Center
Attention EPA Docket No. EPA-HQ-OAR-2009-0491
Environmental Protection Agency
Mail code: 6102T
1200 Pennsylvania Ave., NW.
Washington, DC 20460

Subject: Comments by Entergy Services, Inc.
Federal Implementation Plans to Reduce Transport of Fine Particulate Matter and Ozone
EPA Docket No. OAR-2009-0491

Dear Sir/Madam:

On behalf of itself and its operating affiliates, Entergy Services, Inc. ("Entergy") submits the following comments in response to the U.S. Environmental Protection Agency's ("EPA's") proposed "Federal Implementation Plans to Reduce Transport of Fine Particulate Matter and Ozone" (75 Federal Register 45210 (August 2, 2010)).

Entergy is an integrated energy company engaged primarily in electric power production, transmission, and retail distribution operations. Entergy owns and operates power plants with about 30,000 megawatts of electric generating capacity, and is the second-largest nuclear generator in the United States. Entergy delivers electricity to 2.7 million utility customers in Arkansas, Louisiana, Mississippi, and Texas.

As it supported most elements of the Clean Interstate Air Rule ("CAIR"), Entergy supports the Proposed Clean Air Transport Rule (Transport Rule) as an effective way to reduce ozone and fine particulate levels in the eastern United States. We support EPA's preferred approach that sets a pollution limit (or budget) for each of the 31 states and the District of Columbia. We also agree that allowing unlimited intrastate trading combined with limited interstate trading among power plants is an effective means to assure each state will meet its pollution control obligations and minimize downwind contributions.

Entergy Supports The Integrated Planning Model (IPM) Results to Determine State Budgets, With Qualifications

Results from the IPM market simulation tool played a significant role in developing the budgets EPA has proposed for the Transport Rule. As a result, the EPA's IPM input assumptions have a significant impact on the nature and stringency of the proposed Transport Rule. One such key assumption is natural gas resources, as gas price projections have the potential to strongly affect the dispatch of generating units. In the original Base Case (v3.02), natural gas input assumptions produced gas prices that differ considerably from forward market projections (used to represent an objective "industry view"). For example, Henry Hub gas prices average about $7.25/MMBtu from 2012-2015 in the original Base Case (v.3.02), whereas the current futures for that timeframe average approximately $5.75/MMBtu. Entergy agrees with EPA's use of the IPM in determining the NO_x emissions budgets of the affected states and believes that with the right assumptions, IPM adequately depicts future demand needs at regional and state levels. However, Entergy encourages EPA to use the Energy Information Administration's Annual Energy Outlook natural gas resource forecast contained in v4.10_AEO Gas in the final rule, as these assumptions more accurately predict market futures based on current information.

Entergy Does Not Support Using Integrated Planning Model (IPM) Results for Unit Allowance Allocations

Entergy urges EPA to reconsider the use of the IPM results in allocating NO_x allowances from the state budgets among the individual sources. IPM is a production cost simulation model focused on analyzing wholesale power markets and assessing competitive market prices based on an analysis of the fundamentals relating to supply and demand. While it is capable of producing projections of emissions by taking an integrated approach to regional fuel, power, and emission markets, IPM possesses several characteristics that may contribute to its under-prediction of unit operations and premature retirement or significant reduction of generation from oil/gas steam units. This is demonstrated in the data contained in Attachment A. A review of this data reveals IPM modeling marks the early retirement 23 Entergy oil/gas steam units that were utilized significantly in 2007-2010 to supply power to the grid and underutilizes 10 Entergy combustion turbine units that were utilized significantly in 2007-2010 to supply power to the grid. Entergy does not have any plans to retire the units predicted to retire, nor do we expect utilization of these units or the turbines to change significantly. The table below shows the difference in allowances allocated to these units using the IPM 2012 projected utilization verses an allocation based on the ratio of the unit's average 2007 – 2009 heat input and the 2007-2009 respective state heat input.

Table 1: Entergy Units Project to Retire or Underutilized by IPM

IPM Allocation vs. Allocation Based on 2007-2009 Average Heat Input

	2012 IPM Allocation	2007-2009 Avg HI Allocation	Diff IPM-Avg HI
Seasonal NOx Allowances	470	9,539	-9,069
Annual NOx Allowances	500	12,990	-12,490

The first IPM characteristic causing these unrealistic projections is that, as a regional model, IPM represents the electric transmission system on an interregional basis, with regional boundaries determined by known transmission bottlenecks. Unlike ICF's private sector version of IPM that contains 104 U.S. regions, EPA's version contains only 32. Entergy is modeled as a single region, an over- simplification that might have limited impact for state-level modeling results, but which becomes problematic when relying on detailed regional results, especially at the individual source level. Transmission-related issues inherent to IPM's regional models include missing intraregional load pockets, voltage support, ancillary services, local requirements, etc. These limitations are further exacerbated by the limited number of regions in EPA's IPM, resulting in the premature reduced generation from oil/gas steam units as depicted in Attachment A.

The second issue is the lack of time detail in EPA's version of IPM which underestimates the operational value of oil/gas steam units. Oil/gas steam units are typically responsive to short term fluctuations in demand and are used frequently to provide operational flexibility. IPM, which is not an hourly model and dispatches to broader time segments, has no way of capturing the daily and hourly dispatch decisions that might drive generation for these units.

There are additional modeling assumptions that may contribute to reduced oil/gas steam unit dispatch (overstating turndown requirements, such that units may ramp at low levels for a more limited variable cost than what is represented in IPM, etc.), but the core issue is that IPM is a model that assumes perfect system optimization. The IPM model predicts a least-cost scenario for the electric power system while ignoring these stated system limitations. In none of the three Base Cases was there any projected generation attributed to the 'Oil/Gas Steam' capacity type. Attachment A contains a brief explanation of why Entergy's oil/gas steam units will be utilized even though the IPM model shows zero utilization.

In summary, IPM does not consider a range of real-life factors that influence a company's decision to operate a unit. As a result, allocating allowances to emission units on the basis of IPM modeling creates unrealistic scenarios such as running natural gas combined cycle units at higher utilization than can be accommodated by the local natural gas pipeline network, running coal units so they emit higher than permitted annual emissions, and not running units that are required to operate to meet load/transmission requirements. These distortions of the electricity market are masked when data are aggregated at the state level for setting state budgets but result in obvious inaccuracies and inequities when used at the unit level to allocate allowances. For these reasons, Entergy encourages EPA to reconsider the use of the IPM as a fair means of allocating allowances and supports the use of a proven, reliable methodology of allocating allowances, such as historical MW output. The inequity in the utilization of IPM projections as compared to the proven, reliable method of allocating allowances on historical heat input is depicted in Attachment A.

Alternative Unit Allocation Methodologies

Entergy supports output-based allocation approaches. An output-based allocation relies on energy production (output; megawatt-hour [MWh]) as the basis for determining the number of allowances that a unit will receive. The benefits of an output-based allocation include promoting more efficient and cleaner production of electricity to maintain economic competitiveness. Further, the methodology does not penalize companies and their customers for investments made in cleaner generation prior to a regulatory mandate. Alternatively, Entergy proposes that EPA consider a historic fuel-input basis for unit allocations. The historic basis should be a unit's proportion of its state's historic heat input (i.e., million British thermal units, mmBtu), as was originally proposed for CAIR, prior to the introduction of the fuel adjustment factors. We note that the federal appellate court invalidated the use of fuel factors, not the use of historic heat input. The historic heat input should be based on the maximum annual heat input for units during the period of calendar years 2007 through 2009. We recommend using the annual maximum of reported data during the three-year period rather than the average of those three years in order to ensure that an atypical year does not dramatically affect the allocation (e.g., the unusually low utilization in 2009). Such an allocation methodology would address Entergy's concern with allocations based on modeled future emissions with its known inaccuracies and would be based on verified data that companies have already submitted to EPA.

Heat Input Adjustment Methodology

In EPA's technical support document "State Budgets, Unit Allocations, and Unit Emission Rates," the motivation and methodology for the heat input adjustment is described:

> "Reported annual and ozone season NO_X emissions are adjusted to account for unusually low utilization in 2009. For units reporting emissions (Sets A and B), the annual emissions assumed in the budget calculation are calculated by applying the 2008 heat input to the annual average emissions rate determined from the most recent quarter 1, quarter 2, quarter 3, and quarter 4 (and potentially adjusted for controls, as described above). 2009 heat input is used for units which did not report 2008 heat input data. Ozone season emissions are assumed to be 2008 ozone season heat input multiplied by the most recent ozone season average emissions rate."[1]

The intent of this adjustment is to rebase emissions on a more historically representative heat input year as a way to increase annual NOx emissions and provide a more appropriate allocation level. However, in Arkansas the heat input adjustment often works to reduce reported NOx emissions from Entergy's units. The table below displays each of Entergy's Arkansas units that was assigned a non-zero heat input adjustment by EPA.

Table 2: Entergy Arkansas Units Receiving a Heat Input Adjustment

Unit	Reported Ozone Season NOx Emissions (tons)		
	Pre-Heat Input Adjustment	Post-Heat Input Adjustment	Heat Input Adjustment
Cecil Lynch 3	32	18	-14
Harvey Couch 2	234	0	-234
Independence 1	3,430	3,798	367
Independence 2	3,382	2,760	-622
Lake Catherine 4	191	157	-34
White Bluff 1	2,625	2,590	-35
White Bluff 2	3,695	3,623	-72
Total	**13,589**	**12,946**	**-643**

[1] Technical Support Document (TSD) for the Transport Rule Docket ID No. EPA-HQ-OAR-2009-0491: http://www.epa.gov/airquality/transport/pdfs/TSD_StateBudgets_July152010.pdf

Every heat input adjustment except for the adjustment at Independence 1 revised the reported NOx emissions lower, reducing Entergy's overall allocation by approximately 643 tons. This outcome appears to stand in direct contradiction to the stated purpose of the heat input adjustment. As demonstrated by the Harvey Couch 2 unit allocation, the methodology for determining the adjustment is problematic and can produce results that are difficult to justify. Harvey Couch 2 does not have a listed heat input for any quarter of 2008; this fact reduces the unit's 2009 reported emissions of 234 tons to zero as the basis for its 2012 allocation.

Table 3: State Budget Methodology for States Subject to Transport Rule Regulations

State	SO2	Annual NOx	Seasonal NOx
Arkansas	N/A	N/A	Reported
Louisiana	Reported	Projected	Projected
Mississippi	N/A	N/A	Projected
Texas	N/A	N/A	Reported

If any of the state budget methodologies switch from projected to reported emissions, the heat input methodology will become even more important. In several instances, the current methodology produces counterintuitive results. For example, Little Gypsy 1 has reported emissions of 636 tons under the Annual NOx program. EPA then applied a heat input adjustment that zeroes out Little Gypsy 1's emissions. In EPA's reported data, the unit has heat input values listed for all but the first quarter of 2008. Under the methodology, if there is a single null value in any quarter of 2008, the annual heat input becomes zero and reported Annual NOx emissions are eliminated. In this way, the final reported NOx emissions of Little Gypsy 1 are lower under the Annual Program (0 tons) than under the Seasonal Program (407 tons), because the null heat input value happens to be in the first quarter of 2008.

For a revision intended to produce a more equitable NOx allocation level, the heat input adjustment may be functioning to produce the opposite result. Using the highest heat input value in a consecutive three year period as outlined in the section of these comments describing the A**lternative Unit Allocation Methodologies** would alleviate undesirable results when adjusting heat input to produce a more equitable NOx allocation level.

Emergency Variance Provision

Under either of the three options developed by EPA in the proposed rule, very little, if any, flexibility is provided for generating facilities that may be called on to provide electricity at unexpectedly high levels due to an emergency, natural disaster, long-term mechanical problem, shutdown because of a change in law or regulation, or other similar issue that forces a low- or no-emission facility to reduce its generation capacity significantly. For example, the unexpected shutdown, for whatever reason, of a nuclear or hydroelectric facility that normally produces a significant generating capacity in a state, with no emissions from its electric generating functions, likely would require a corresponding increase in fossil generation in an amount that could exceed the maximum emissions allowed by the combination of allowances issued to the state plus the limited interstate trading which may be allowed by the rule. Of course, a rule that allowed no interstate trading would be in even greater need of such an emergency variance provision. The variance provision should allow states implementing the Transport Rule to grant a variance from the requirement for holding or obtaining allowances for those tons of emission created by a unit's response to another unit's emergency or unanticipated loss of generation.

Proposed Compliance Date

Entergy would also like to comment on the complications associated with the proposed compliance dates of January 1, 2012 for Phase I and January 2, 2014 for Phase II of the rule. For the reasons stated below Entergy cannot support a compliance date of January 1, 2012 unless the inequities of the allowance allocations to Entergy units caused by the use of the Integrated Planning Model are corrected. If a final rule is not issued until the middle of 2011, as suggested by EPA, it is unreasonable to assume that a utility can develop a compliance strategy based on short allowance budgets for each State's fleet, schedule outages, install controls, and train operators to operate these controls efficiently by January 1, 2012. Even after the most cost effective compliance strategy is developed, it has been Entergy's experience that this will take a minimum of 2 years to evaluate, finance, award a bid, schedule outages, permit, construct, train, and have fully operational pollution control equipment. Entergy has reviewed EPA's technical document, EPA-HQ-OAR-2009-0491 – Installation Timing for Low NO_x Burners, and disagrees that utilities can complete "*engineering, fabrication, delivery and installation*" of pollution control equipment in a 6 month time frame, much less at a time when pollution controls will be offered at a premium and contractor availability throughout the country may be limited.

Applicability of Clean Air Transport Rule to Louisiana

1. **EPA Proposed Finding of Interference With Maintenance of Annual PM2.5 NAAQS**

Entergy adopts comments I.B and I.C made by the Louisiana Chemical Association. Entergy does not believe that the state of Louisiana is interfering with the maintenance of $PM_{2.5}$ attainment in downwind states. Louisiana, therefore, should not be regulated in the annual program in the final rule. In the proposed rule, Louisiana is in the annual program because of a 0.34 μg/m3 $PM_{2.5}$ contribution to one monitor (Clinton Drive monitor) in Harris County, TX. Since 2004, all $PM_{2.5}$ monitors in the Houston area except the Clinton Drive monitor have recorded readings less than 15.0 μg/m3. $PM_{2.5}$ data for the Clinton Drive monitor showed a 2005 annual average of 15.9 μg/m3 and a three-year average of 15.0 μg/m3. The Texas Commission on Environmental Quality (TCEQ) conducted an advanced analysis of the $PM_{2.5}$ data, meteorological data, and the chemical speciation data to identify the cause (what portion and component of $PM_{2.5}$), source types, and source areas contributing to the excessive particulate matter concentrations. Daytime, weekday concentrations are the main cause of high $PM_{2.5}$ levels at the Clinton Drive site. Analysis of chemical speciation data shows the calculated mass of soil at Clinton Drive is approximately 1.5 to 2.0 μg/m3 higher than at any other speciation monitoring site in the Houston area. The data indicates that the higher elevated $PM_{2.5}$ concentrations at the Clinton Drive monitor represent a limited area that is impacted by local fugitive emissions, as the Clinton Drive monitor is located directly across from the entrance to the Port of Houston Authority (PHA) and unpaved ship yards along the Houston Ship Channel. A railroad also runs parallel to this section of Clinton Drive.

Concurrently, the TCEQ began working with the PHA, the City of Houston, Harris County, and local industry to address this issue. The combined efforts of the various organizations has improved particulate matter air quality to the point that the 2008 $PM_{2.5}$ annual average at Clinton Drive was 14.0 μg/m3, even when exceptional event days are included. Without removing exceptional event days, the 2006 through 2008 design value for Clinton Drive was 15.2 μg/m3. After removing exceptional event days identified by TCEQ meteorologists, the 2006 through 2008 design value was 14.6 μg/m3. Without removing exceptional event days, the 2007 through 2009 design value for Clinton Drive was 14.1 μg/m3. The annual readings for the Clinton Drive monitor show a steady decline during the last 4 years.

2006 – 16.0 μg/m3
2007 – 15.6 μg/m3
2008 – 14.0 μg/m3
2009 – 12.6 μg/m3

This data demonstrates that the $PM_{2.5}$ issue at the Clinton Drive monitor was caused by local conditions and that those local corrective actions had improved the air quality to an attainment status.

Realizing that the $PM_{2.5}$ issues at the Clinton Drive monitor are a local problem, and in anticipation of the strengthening of the NAAQS for $PM_{2.5}$, a taskforce committee consisting of members from the TCEQ, Texas Department of Transportation (TxDOT), Harris County, the City of Houston, the PHA, and the Houston-Galveston Area Council was organized to address this issue. The taskforce committee established a scope for projects on Clinton Drive that prevent disturbing $PM_{2.5}$ dust and will ensure these local issues are addressed. See Attachments Clinton Drive 1, Clinton Drive 2, Clinton Drive 3, Clinton Drive 4.

Because the pollution causing the only purported Transport Rule related exceedences connected to Louisiana was caused by local conditions, these local conditions have been addressed, these conditions will continue to be addressed in the future, and the monitor is now demonstrating attainment of the $PM_{2.5}$ standard, Louisiana should ***not*** be in the annual program of the Clean Air Transport Rule.

Furthermore, even if there were a downwind transport problem of NOx and SO_2 from Louisiana, Table IV.C-1-2005 Base Case SO_2 Emissions (Tons/Year) For Eastern States By Sector and Table IV.C-2-2005 Base Case NO_x Emissions (Tons/Year) For Eastern States By Sector in the proposed rule, clearly indicate that the regulation of EGU's in Louisiana is not the solution to solving the problem, as EGU emissions for those pollutants in Louisiana are considerably less than non-EGU emissions of each pollutant.

2. **The Projected Impact from Louisiana Emissions Is Less than a PSD Significant Impact Level**

Entergy adopts comment I.D made by the Louisiana Chemical Association. Entergy believes that EPA cannot set the level for "interference with maintenance" of a NAAQS lower than the EPA Significant Impact Level ("SIL") used under the Prevention of Significant Deterioration ("PSD") program. Entergy intends this as a general comment on EPA's proposed methodology for determining when there is "interference with maintenance" within the meaning of CAA and as a specific comment with respect to the projected impact of Louisiana emissions on Harris County, Texas.

As part of the analysis of air quality impacts to determine compliance with the NAAQS and increment, the permit applicant and reviewing authority may compare the source's impacts for a pollutant with the corresponding SIL for that pollutant to show that a cumulative air quality impacts analysis is not necessary.

Harris County is within a Class II air quality control district. On September 21, 2007, EPA proposed the following options for a SIL for the PM2.5 Annual NAAQS for a Class II area:[2]

Option 1	1.0 ug/m^3
Option 2	0.8 ug/m^3
Option 3	0.3 ug/m^3

The EPA projected value for Louisiana impacts to the Clinton Drive monitor in Harris County is 0.34 ug/m^3. Such value is well below the Option 1 and 2 proposed SILs and does not exceed the Option 3 SIL, with standard rounding conventions. While EPA has not yet finalized the proposed SILs pursuant to the 2007 notice, it is our understanding that EPA has reached a final decision, that decision has been reviewed by the Office of Management and Budget, and that a final rule adopting one of these 3 values will be published in the Federal Register in October 2010.

In the September 21, 2007 Federal Register notice proposing SILs for the PM2.5 annual NAAQS, EPA provided the following explanation of the concept and appropriate usage of a SIL:

> Significant Impact Levels or SILs are numeric values derived by EPA that may be used to evaluate the impact a proposed major source or modification may have on the NAAQS or PSD increment. The SILs currently appear in EPA's regulations in 40 CFR 51.165(b), which are the provisions that require States to operate a preconstruction review permit program for major stationary sources that wish to locate in an attainment or unclassifiable area but would cause or contribute to a violation of the NAAQS. The SILs in that regulation are the level of ambient impact that is considered to represent a "significant contribution" to nonattainment.

Although 40 CFR 51.165 is the regulation that establishes the minimum requirements for nonattainment NSR programs in SIPs, the provisions of 40 CFR 51.165(b) are actually applicable to sources located in attainment and unclassifiable areas. See 40 CFR 51.165(b)(4). Where a PSD source located in such areas may have an impact on an adjacent non-attainment area, the PSD source must still demonstrate that it will not cause or contribute to a violation of the NAAQS in the adjacent area. This demonstration may be made by showing that the emissions from the PSD source alone are below the significant impact levels set forth in 40 CFR 51.165(b)(2). However, where emissions from a proposed PSD source or modification would have an ambient impact in a non-attainment area that would exceed the SILs, the source is considered to cause or contribute to a violation of the NAAQS and may not be issued a PSD permit without obtaining emissions reductions to compensate for its impact. 40 CFR 51.165(b)(2)-(3).

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[2] 72 Fed.Reg.54112-54156, Sep. 21, 2007.

The EPA has also applied SILs in other analogous circumstances under the PSD program. Based on EPA interpretations and guidance, SILs have also been widely used in the PSD program as a screening tool for determining when a new major source or major modification that wishes to locate in an attainment or unclassifiable area must conduct a more extensive air quality analysis to demonstrate that it will not cause or contribute to a violation of the NAAQS or PSD increment in the attainment or unclassifiable area.

* * *

Subsequently, in draft guidance for permit writers, EPA advised that SILs may be used to determine whether a source needs to conduct a cumulative or "full" impact analysis to demonstrate that in conjunction with all other increment consuming sources, it will not cause or contribute to violation of the NAAQS or PSD increment in an attainment or unclassifiable areas. New Source Review Workshop Manual, at C.24-C.25 (Draft 1990); See also 40 CFR 51.166(k); 40 CFR 52.21(k). Permitting authorities followed this guidance, and this approach remains an accepted aspect of PSD program implementation. ***If based on a preliminary impact analysis, a source can show that its emissions alone will not increase ambient concentrations by more than the SILs, EPA considers this to be a sufficient demonstration that a source will not cause or contribute to a violation of the NAAQS or increment***.

* * *

The concept of a significant impact level is grounded on the de minimis principles described by the court in Alabama Power Co. v. Costle, 636 F.2d 323, 360 (D.C. Cir. 1980). In this case reviewing EPA's 1978 PSD regulations, the court recognized that "there is likely a basis for an implication of de minimis authority to provide exemption when the burdens of regulation yield a gain of trivial or no value." 636 F.2d at 360.

* * *

Similarly, significant impact levels are intended to identify a level of ambient impact on air quality concentrations that EPA regards as de minimis. ***The EPA considers a source whose individual impact falls below a SIL to have a de minimis impact on air quality concentrations. Thus, a source that demonstrates its impact does not exceed a SIL at the relevant location is not required to conduct more extensive air quality analysis or modeling to demonstrate that its emissions, in combination with the emissions of other sources in the vicinity, will not cause or contribute to a violation of the NAAQS at that location.***[3]

In other words, if a single point source within the Houston area had a project that triggers PSD for PM2.5, but the screening modeling indicates that the projected air quality impact for that project is below the SIL, in this case, at or below the level of one of EPA's proposed three options 1.0, 0.8 or 0.3 ug/m^3, then that source would not be considered to have only a *de minimis* impact on air quality and would not be required to conduct modeling to demonstrate that its emissions, in combination with those of other sources, will not contribute to a NAAQS violation. If a single point source has emissions that are considered *de minimis* when at or below a SIL, then it would be arbitrary and capricious to require any regulation, let alone widespread controls on sources in another state, such as Louisiana, that cumulatively have an equivalent or lesser impact than would such individual source.

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[3] 72 Fed.Reg. at 54139-54139 (emphasis added).

For this reason, EPA should reverse its proposed finding that Louisiana emissions are likely to interfere with maintenance of the annual PM2.5 NAAQS in Harris Co., Texas.

The EPA Projection that Louisiana Emissions Sources Will Interfere With Maintenance in Harris County, Texas, Is Flawed. EPA Has Projected Significant Reductions of SO2 and NOx Even Without the Transport Rule and FIP

Entergy adopts comment E.1 made by the Louisiana Chemical Association. In addition to the comments above, Entergy believes that EPA's projection that Louisiana emissions will interfere with maintenance of the annual PM2.5 NAAQS at the Clinton Drive monitor without further controls is flawed.

EPA modeling shows that virtually the entire impact on PM2.5 annual levels at the Clinton Drive monitor are due to sulfate emissions. The following data, taken from EPA Preamble Tables IV.C-1, IV.C-3 and IV.C-5, and based on the IPM v.3.02 modeling, demonstrate that SO2 emissions from Louisiana will significantly decline, without enactment of the Transport Rule or a FIP:

Table 4: SO2 Emissions in Tons Per Year – EPA IPM v.3.02 Base Case Modeling

State	TR Case	EGU	NonEGU	NonPt	NonRd	OnRd	Fires	Total
Louisiana	2005 Base Case[4]	109,851	165,737	2,378	73,233	2,399	892	354,489
Louisiana	2012 Base Case[5]	100,239[6]	159,722	2,373	78,051	455	892	341,731
	Change from 2005 to 2012	-9,612	-6,015	-5	+4,818	-1,944	0	-12,758
Louisiana	2014 Base Case[7]	94,824	151,216	2372	78,097	470	892	327,871
Change from 2005 to 2014	Change from 2005 to 2014	-15,027	-14,521	-6	+4,864	-1,959	0	-26,618

[4] 75 Fed.Reg. at 45239, Table IV.C.1 – 2005 Base Case SO2 Emissions (Tons/Year) for Eastern States By Sector.

[5] 75 Fed.Reg. at 45240, Table IV.C.3 – 2012 Base Case SO2 Emissions (Tons/Year) for Eastern States By Sector. The Preamble at this page states: "The future base case scenarios represent predicted emissions in the absence of any further controls beyond those federal measures already promulgated."

[6] This value is stated in Table IV.C.3 of the Preamble. However, a summation of all SO2 emissions from Louisiana sources in the EPA parsed files for the TR Base Case v. 3.02 run is 98,110 tpy. Entergy is not sure why there is a discrepancy, but notes this issue. In any case, there is still a significant reduction of SO2.

[7] 75 Fed.Reg. at 45242, Table IV.C.5 – 2014 Base Case SO2 Emissions (Tons/Year) for Eastern States By Sector.

In summary, EPA's own modeling shows that without the Transport Rule/FIP, overall emissions of SO2 in Louisiana will decrease by 12,758 tpy from 2005 levels by 2012 and by 26,618 tpy from 2005 levels by 2014. As discussed above, Harris County, Texas is currently in attainment with the annual PM2.5 NAAQS and has a strong downward trend of PM2.5 emissions over the past several years. If Louisiana SO2 emissions are not causing interference with maintenance now, and are projected to have this significant of a decrease of SO2 without the Transport Rule, then how can EPA reasonably conclude that Louisiana is likely to interfere with maintenance of the PM2.5 standard in Harris County or that the Transport Rule is justified for Louisiana? If greater emissions are not affecting maintenance, then how can lesser emissions affect maintenance? Entergy believes that it would be arbitrary and capricious for EPA to arrive at this as a final conclusion.

Table 5: NOx Emissions in Tons Per Year – EPA IPM v.3.02 Base Case Modeling

State	TR Case	EGU	NonEGU	NonPt	NonRd	OnRd	Fires	Total
Louisiana	2005 Base Case[8]	63,791	165,162	27,559	301,170	112,889	3,254	673,824
Louisiana	2012 Base Case[9]	44,773[10]	161,724	27,525	285,562	64,074	3,254	586,912
	Change from 2005 to 2012	-19,018	-3,438	-34	15,608	-48815	0	-86,912
Louisiana	2014 Base Case[11]	45,457	161,766	27,515	274,697	52,360	3,254	565,049
Change from 2005 to 2014	Change from 2005 to 2014	-18,334	-3,396	-44	-26,473	-60,529	0	-108,775

As can be seen by this data, EPA also projects that these NOx emissions will decrease by 108,775 tpy (a 16% decrease), even without the Transport Rule/FIP. As noted above, EPA's modeling demonstrates that Louisiana NOx emissions appear to have almost no impact on the resulting levels of PM2.5 in Harris County, Texas as the nitrate component of the Louisiana impact was only 0.004 ug/m^3. Thus, there is no reason to expect that NOx emissions will contribute to interference with attainment in Harris Co., Texas in the future as they are not causing interference now.

[8] 75 Fed.Reg. at 45240, Table IV.C.2 – 2005 Base Case NOx Emissions (Tons/Year) for Eastern States By Sector.

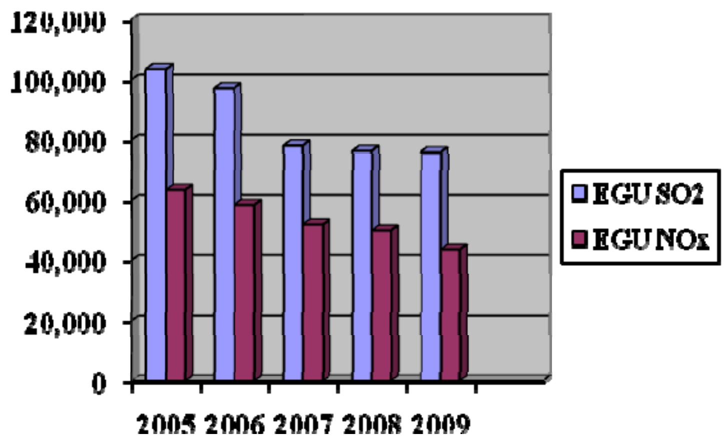
[9] 75 Fed.Reg. at 45242, Table IV.C.4 – 2012 Base Case NOx Emissions (Tons/Year) for Eastern States By Sector. The Preamble at this page states: "The future base case scenarios represent predicted emissions in the absence of any further controls beyond those federal measures already promulgated."

[10] This value is stated on Table IV.C.4; however, the value in the stated budget for Louisiana is 43,946 tpy in Table IVE-1. Entergy is not sure why there is a discrepancy as the state budget was supposed to be equivalent to the TR Base Case projected value for NOx, according to the Preamble.

[11] 75 Fed.Reg. at 45243, Table IV.C.6 – 2014 Base Case NOx Emissions (Tons/Year) for Eastern States By Sector.

Moreover, actual certified SO2 and NOx data submitted to EPA's Clean Air Markets Division pursuant to the Acid Rain and CAIR programs confirms a significant decline in actual SO2 and NOx reductions statewide from Louisiana EGUs over the past five years:

Figure 1: **Louisiana EGU Actual Reported SO2 and NOx** (tpy)[12]



In fact, actual certified totals of SO2 and NOx in 2009 were already well below the values projected by EPA for the Base Case 2012 and 2014 levels for Louisiana EGUs, whether projected by TR Base Case v.3.02 or v.4.10.

While Entergy has not been able to complete its review of the changes to the TR Base Case v. 4.10 [13]compared to TR Base Case v. 3.02, nor of the evaluation of different Transport Rule FIP options using version 4.10, it is imperative for EPA to realize that the total SO2, annual NOx and ozone season NOx estimates under the TR Base Case v. 4.10 have dropped dramatically when compared to the TR Base Case v. 3.02. The reduction in each case is greater than the difference between the TR Base Case v. 3.02 and the TR SB Limited Trading Values. This difference is what EPA has stated to be the amount to be removed in order to prevent "significant contribution" or "interference with attainment." **In short, this means that EPA projects with the updated version of the IPM that by 2012, the total reduction required in order to prevent any significant contribution or interference with maintenance has already been achieved without the Transport Rule/FIP.** The following Table makes that comparison:

Table 6: Comparison of TR Base Case v. 3.02 to v.4.10 for Louisiana EGUs

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[12] Data from Environmental Protection Agency, Clean Air Markets Division, Where You Live, Louisiana State Map; all programs, 2005-2009, http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=whereyoulive.state&displaymode=view&programYearSelection=none&prg_code=ALL&year=2009&state=LA (last visited September 25, 2010).

[13] Environmental Protection Agency, EPA's IPM's Base Case v. 4.10, IPM v. 4.10 Data Runs and Parsed Files, IPM Run Name, TR Base Case v. 4.10, available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html.

	TR Base Case v. 3.02 for Louisiana EGUs[14]	TR Base Case v. 4.10 totals for Louisiana EGUs	Reduction	Required Reduction to Eliminate Significant Contribution or Interference With Maintenance[15]
SO2 tpy	100,239	80,381	19,858	7,070
NOx – Annual tpy	43,946	32,804	11,142	8,835
NOx- Ozone Season tpy	21,220	15,159	6,061	4,583

Because "significant contribution" and "interference with maintenance" have been removed with this revised IPM modeling, there is no basis for a Transport Rule or FIP for Louisiana EGUs, as the levels required to remove significant contribution and interference with maintenance will have already been achieved. In summary, EPA's IPM modeling provides no rational basis for the FIP proposed for Louisiana. It supports a conclusion that any potential Louisiana impact on either annual PM2.5 or 8-hour ozone NAAQS in Texas will be removed through factors other than the Transport Rule and CAIR.[16]

In the Alternative, Louisiana Should Only Be In the Annual SO2 Program

If EPA determines in the final Transport rule that Louisiana should be regulated under the annual program, then clearly Louisiana should be regulated under the annual program for SO2 only. In the proposed rule, EPA has determined that Louisiana should be in the annual program of the Transport Rule because, according to EPA's analysis, Louisiana is interfering with the maintenance of attainment for the annual standard at the Clinton Drive monitor in Harris County, TX. Further, EPA projected that the impact of Louisiana emissions on that monitor would be 0.34 *u*g/m3. A review of the Annual PM Sulfate Contributions and Annual Nitrate Contributions contained in EPA's Air Quality Contributions Data, available at EPA's Technical Support Documents for the Proposed Transport Rule, reveals that the vast majority of the projected impact of Louisiana emissions on the Clinton Drive monitor was contributed by sulfate emissions (0.337 *u*g/m3) and only 0.004 *u*g/m3 was contributed by nitrate emissions. Clearly, it makes no sense to include Louisiana in the annual program for NOx emissions in the transport rule with such a minimum impact on downwind compliance when the significance threshold in the proposed rule is 0.15 *u*g/m3.

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[14] Data in this table are from 75 Fed.Reg. 45291, Tables IV-E-1 and IV-E-2. This is the value Entergy believes that EPA used in the modeling to determine significant contribution or interference with maintenance. See Environmental Protection Agency, Technical Support Document for the Transport Rule, Air Quality Modeling, (2010) http://www.epa.gov/airquality/transport/pdfs/TR_AQModeling_TSD.pdf. EPA indicated that for the air quality modeling, it used the TR Base Case v. 3.02 value for SO2 rather than the lower SO2 state budget, which was based on adjusted, reported data. For NOx and ozone season NOx, EPA has clearly stated used the TR Base Case v. 3.02 projection as the budget and as the value used in modeling air quality impacts.

[15] Again, this is the difference between the TR Base Case v. 3.02 (or for SO2, the state budget as it is lower) and the TR SB Limited Trading parsed run file for Louisiana EGUs.

[16] The TR Base Case modeling is intended to remove the affect of any CAIR controls, as stated numerous times in the Preamble to the proposed Transport Rule/FIP.

Changing the Ozone Season Months

Entergy does not support changing the Ozone Season Program dates from the current season of May – September to March – October as suggested in the proposed rule. The Ozone season should remain consistent with the approach taken by the OTAG, the NOx SIP Call, and the CAIR.

Warren Peaking Power Facility

Entergy would like to take this opportunity to correct an error in the Mississippi allocation pool of allowances. The proposed rule states that the Warren Peaking Power Facility (ORIS 55303) is located in Mississippi when in fact these four peaking units were decommissioned, sold, and relocated to two non-Entergy sites in Texas in 2008. Two of the units were installed at the San Jacinto County Peaking Facility (ORIS 56603) and the other two units were installed at the Hardin County Peaking Facility (ORIS 56604). Entergy requests that EPA remove the Warren Peaking Power Facility from the Mississippi pool and add the San Jacinto County and Hardin County Peaking Facilities to the Texas pool of allowances.

Nelson Industrial Steam Electric Company (NISCO) Units

Entergy would like to take this opportunity to correct an error in the Louisiana allocation pool of allowances. The proposed rule states that NO_x and SO_2 allowances are allocated to R S Nelson, ORIS Code 1393, Units 1A and 2A. These units are actually named Nelson Industrial Steam and Operating Company (NISCO), ORIS Code 50030, Units 1A and 2A. Entergy requests that EPA correct this error in the final regulation so the NISCO units are awarded the appropriate allowances.

Entergy appreciates the opportunity to provide these comments and recommendations to the Agency. We look forward to working with EPA staff with the implementation process. Should you have questions regarding these comments, please contact Joe Hantz, Manager Environmental Services, at (281) 297-3319 or Stuart Bier, Senior Environmental Analyst at (281) 291-3386.

Respectfully submitted,

Joseph Hantz

Joseph Hantz
Manager Fossil Environmental Services

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Exhibit F

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February 7, 2011

Air and Radiation Docket and Information Center
Attention EPA Docket No. EPA-HQ-OAR-2009-0491
Environmental Protection Agency
Mail code: 6102T
1200 Pennsylvania Ave., NW.
Washington, DC 20460

Subject: Comments on Notice of Data Availability for Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone: Request for Comment on Alternative Allocations, Calculation of Assurance Provision Allowance Surrender Requirements, New-Unit Allocations in Indian Country, and Allocations by States
EPA Docket No. OAR-2009-0491

Dear Sir/Madam:

On behalf of itself and its operating affiliates, Entergy Services, Inc. ("Entergy") submits the following comments in response to the U.S. Environmental Protection Agency's ("EPA's") proposed "Notice of Data Availability for Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone: Request for Comment on Alternative Allocations, Calculation of Assurance Provision Allowance Surrender Requirements, New-Unit Allocations in Indian Country, and Allocations by States" (76 Federal Register 1109 (January 7, 2011)).

Entergy is an integrated energy company engaged primarily in electric power production, transmission, and retail distribution operations. Entergy owns and operates power plants with about 30,000 megawatts of electric generating capacity, and is the second-largest nuclear generator in the United States. Entergy delivers electricity to 2.7 million utility customers in Arkansas, Louisiana, Mississippi, and Texas.

Entergy appreciates the opportunity to comment on the EPA's Notice of Data Availability associated with the proposed Clean Air Transport Rule. We support the EPA's efforts to address concerns we, along with many others, expressed during the initial comment period for the Clean Air Transport Rule and offer the following comments on the January 7 NODA.

Entergy Supports The Proposed Option 1 Methodology For Allocating Allowances

While Entergy has long supported allocation methodologies based on energy output (megawatt hours), Entergy also supports the use of historical heat input as a means of distributing unit allowances as proposed in the EPA's Option 1. In our October 1, 2010 comments on the proposed CATR Entergy encouraged the EPA to reconsider the use of the Integrated Planning Model as a fair means of allocating allowances and supported the use of a proven, reliable methodology of allocating allowances, such as historical MW output or historical heat input, similar to what has been proposed in Option 1. As the EPA has pointed out in the NODA, the use of historic heat input data is more likely to be accurate at a unit level than projected unit-level emissions, is fuel-neutral, and is emission-control neutral (does not penalize units that have installed or are planning to install pollution control technology), making it the most equitable methodology to distribute allowances. We are concerned that Option 2 introduces too many potential adjustment factors to be cleanly implemented without legal challenge in the short time EPA has to finalize the rule.

Calculation Of Assurance Provision Allowance Surrender Requirements

Entergy supports the calculation of assurance provision allowance surrender requirements on a Designated Representative (DR) basis. As the EPA has mentioned in the NODA, imposing the proposed assurance provision allowance surrender requirement at the DR level, rather than owner level, potentially provides owners and operators with more flexibility than under the approach in the proposed Transport Rule while ensuring that the issue of interstate transport is addressed.

Allocations by States

In the unfortunate event the EPA elects not to finalize either Option 1 or Option 2 proposed in the NODA, Entergy strongly supports adding provisions to the Transport Rule that would allow states to replace the EPA's allowance allocation provisions by state-developed allocation provisions similar to what was established in the CAIR.

Entergy appreciates the opportunity to provide these comments and recommendations to the Agency. We look forward to working with the EPA staff with the implementation process. Should you have questions regarding these comments, please contact Joe Hantz, Manager Environmental Services, at (281) 297-3319 or Stuart Bier, Senior Environmental Analyst at (281) 291-3386.

Respectfully submitted,

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Exhibit G

A. Trading System

These comments focus on the structure of the emission trading system envisioned by EPA, including in particular (1) the classification of states into two distinct groups with no trading allowed between groups (Section VI of the preamble); (2) the determination of variability limits (also Section VI); (3) the allocation of allowances (Section VII); (4) the assurance provisions (also Section VII); and (5) the use of banked NOx allowances from the CAIR program (Section IX). Attention is focused on these areas because the reviewers following up on these issues also believe that the scope and stringency of the rule are appropriate in terms of their economic impact; indeed, if anything, based on the analysis EPA has provided, a benefit-cost perspective would support greater reductions in emissions than EPA is requiring (The more stringent scenario has a cost estimate of $2 billion more, with additional benefits of $20 to $50 billion). This makes it seem as though the more stringent scenario would be the preferred one. Moreover, these reviewers believe that the determination of state-level budgets, which was a crucial issue in the court decision regarding CAIR, is both analytically rigorous and responsive to the court's concerns in *North Carolina*. Indeed, EPA is to be commended for the terrific job it has done to produce a rule with benefits that vastly outweigh the costs, in a manner that is responsive to a difficult and disappointing court decision. It is the soundness of the overall rule that provides the opportunity to focus more narrowly on critiquing and potentially improving the design of the market mechanism that EPA envisions to implement it.

These comments are presented according to the order that the issues appear in the preamble. The overarching theme is that the limitations on trading imposed by EPA, although well intended, are likely to greatly impair the program's ability to achieve emissions cost-effectively. Much of the problem can be traced to the design of the assurance mechanism, and in particular the way that it would impose penalties on individual units or groups of units for exceeding an essentially arbitrary limit on emissions.

<u>1. EPA should reconsider its decision to prohibit trading between Groups 1 and 2.</u>

As in the proposal, the final rule would define two distinct groups of states with respect to required SO_2 emissions reductions. Group 1 states are those for which EPA calculates allowable emissions budgets on the basis of a marginal cost threshold of $2300 per ton of SO_2 emissions; Group 2 states are those for which the modeled contribution to downwind air quality problems (nonattainment or interference with maintenance) is eliminated at a marginal control cost of $500/ton. Under the trading system envisioned by EPA, EGUs in Group 1 and Group 2 states would be issued distinct kinds of emission allowances; units in Group 1 states would not be allowed to use Group 2 allowances for compliance, or vice versa.

EPA explains its approach on p. 245 of the Preamble by arguing that "to allow Group 1 or Group 2 allowances to be used interchangeably … would be to allow the shifting of reductions from areas where they are needed to eliminate significant contribution to areas where they are not needed to eliminate significant contribution." But the same logic would apply to <u>any</u> interstate trading. Consider a hypothetical example in which units in state A (in the aggregate) have surplus allowances to sell to units in state B, and units in state B (in the aggregate) have demand for those allowances. Trading between the states would shift reductions from state B to state A. By definition, this results in shifting reductions from "areas where they are needed to eliminate significant contribution to areas where they are not needed" – even if the two states are in the same group. That is because EPA constructs state budgets by calculating the emissions left after subtracting the reductions needed to eliminate a state's significant contribution. As a result, by definition the reductions in state B that end up not occurring are needed to eliminate significant contribution, and the excess reductions in A that result from the trade are not. Hence EPA's main rationale for not allowing intergroup trading fails because it holds equally well for intragroup trading, which EPA allows.

EPA's rationale is unconvincing for a second reason (noted by the commenters): any restrictions on intergroup trading are entirely unnecessary given the assurance mechanism that EPA is also putting in place. The assurance mechanism ensures that the rule makes measurable progress toward eliminating the significant contribution of upwind states to downwind nonattainment problems. With it in place, no further limitation on trading is necessary. In response, EPA argues that "allowing for trading between the two groups … would increase risk of a state exceeding its variability limit." But again, this argument is unpersuasive, for the same reason as noted above: it applies equally well to trading between any two states, whether or not they are in the same group.

The determination of which states are sellers and buyers of permits depends on the marginal abatement costs, not the level of stringency, though those can be correlated. Has the EPA determined that Group 2 states are more likely to be sellers of permits to Group 1 states that are other Group 1 states?

Meanwhile, there are clear drawbacks to prohibiting intergroup trading. First, maintaining two separate markets will increase the complexity of administering the program – an issue that EPA emphasizes as one of its primary concerns in designing the program elsewhere in the Preamble (e.g. in the discussion of the assurance provisions). Perhaps more importantly, preventing intergroup trading will inhibit trading and reduce market liquidity, limiting the cost-effectiveness of the market mechanism. As discussed below, the assurance mechanism already threatens to interfere with the functioning of the market. But at least in that case there is a clear need for the assurance mechanism as a response to the court's concerns in *North Carolina.* In contrast, there appears to be no good reason for limiting trading among groups of states.

It is worth noting that this is an easy change to make: it would require nothing in the way of new modeling and little work beyond rewriting the Preamble.

- EPA should reconsider its prohibition of intergroup trading in light of these concerns.
- If EPA chooses to continue to prohibit intergroup trading, can it provide any data or modeling to support its concern that allowing intergroup trading will put greater pressure on the assurance mechanism or otherwise undermine the performance of the rule?

<u>2. EPA should consider raising the variability limits to 15% or 20% of the state budgets. At a minimum, more analysis is needed to (i) analyze the historic variability of emissions (not conditional on emissions</u>

rates) and (ii) consider how the choice of 10% interacts with the assurance provisions to translate into limits on emissions at the level of individual units or designated representatives.

EPA elects to use 10 percent as the variability limit in almost all cases, on the grounds that "[m]ost states' historic variability in year-to-year emissions of the covered pollutants … were within 10 percent of their average annual emissions" (p. 261). This variability limit then determine the absolute upper bound for allowable emissions for each state. However, EPA's choice of 10 percent appears to be an unnecessarily tight constraint, for two reasons.

(i) First, EPA states that the variability limit is based on the variation in emissions "holding emission rates constant" – in other words, the variation in heat input but not in total emissions. While EPA is right to note that heat input may vary as a result of factors outside of a unit's control, it is also true that a unit's emissions rate may vary as a result of such factors. For example, coal varies widely in sulfur content – even for coal of otherwise similar characteristics from similar regions. It would not be surprising if the sulfur content of the coal burned in many units varied by at least 5 percent in a given year. As another example, scrubbers may break down, or be taken down for repairs, etc. It is not hard to imagine that relatively short scrubber outages could result in variations of at least 5 percent; given that wet scrubbers typically reduce 95 percent of SO_2 from the flue gas, taking a scrubber offline for a month would increase emissions by roughly 8 percent of uncontrolled emissions (and thus a much larger percentage of controlled emissions).

The point is that absolute emissions at an individual unit may vary from year to year around a long-term average, not only because of variation in heat input but also because of unanticipated and hard-to-control variation in emissions rates. In considering only variation in heat input, EPA is missing an important source of unit-level variation. On the reasonable assumption that variation in heat input and variation in emissions rates are uncorrelated (or at least not negatively correlated), EPA's failure to consider variation in emissions rates will result in an understatement of the true variability in unit-level emissions.

In a trading system, of course, these variations are inconsequential, because they end up as "noise" in unit-level emissions that can be covered by allowance purchases. However, the proposed assurance mechanism would impose penalties at the level of individual DRs for exceeding strict upper bounds on emissions, defined by using EPA's variability limits. Calculating those variability limits on the basis of variation in heat input only, as EPA does, will result in unnecessarily strict limits on compliance flexibility and a corresponding loss in cost-effectiveness.

- Has EPA done an analysis to calculate the variability of absolute emissions (rather than the variability of heat input)?

(ii) Second, in discussing its selection of a variability limit, EPA only considers historical variation at the state level. In doing so, EPA seems to have overlooked the fact that the variability limit will effectively apply at the level of the designated representative (DR) – not at the level of the state. That is because the assurance mechanism penalizes units (aggregated to the DR level) for emissions in excess of their initial allocation plus their share of the state's variability limit. As a result, almost all units (at the DR level) face a hard constraint on their emissions equal to 10 percent above their allocation.

This could severely undermine the cost-effectiveness of the program, since it sharply limits the ability of some units/DRs with relatively high marginal abatement costs to comply by emitting relatively large amounts and buying allowances to cover those emissions.

Nowhere, however, does EPA do any analysis on variability at the DR level. As EPA acknowledges in the context of discussing variability in individual states versus regions, variability is typically lower at higher levels of aggregation. The same applies in reverse: variability is likely to be greater at lower levels of aggregation, e.g. at the level of designated representatives relative to states. Thus even if state-level historical variability is less than 10 percent of annual emissions, variability may be greater than 10 percent at the level of individual units (or DRs).

Moreover, EPA's discussion suggests that the benefits from imposing a 10 percent variability limit rather than a 15 or 20 percent limit are negligible. According to EPA, modeling of different variability limits "suggests that the air quality impacts are small when all upwind states linked to a particular receptor monitor increase their SO_2 emissions to any of the variability levels (5, 10, 15, or 20 percent)." This statement seems to suggest that EPA could fairly easily justify 20% variability limits.

- Has EPA done an analysis of emissions variability at the unit and/or designated representative level? Can it share that analysis with interagency staff?
- In light of the minimal air quality benefits but potentially adverse impacts on cost-effectiveness, EPA should reconsider its choice of a 10 percent variability limit for most state-pollutant pairs, and instead consider using a higher limit (15 or 20 percent). At a minimum, EPA should provide a more explicit discussion of its choice in light of the proposed assurance mechanism.

3. EPA should reconsider its decisions for allocating allowances to new and retired units

Although EPA's basic allocation methodology appears sound, the treatment of units that are entering and exiting the program raises some potential concerns.

(i) For new units, EPA envisions a complicated two-step methodology that is poorly explained in the rule (pp. 365). As a result, it is hard to tell what the impact of the allocation will be. However, it appears that the consequence of EPA's approach – in the absence of a shortage of allowances for new units – will be that units in their first year of operation are guaranteed to receive exactly as many allowances as they need to cover their emissions. In other words, they will face an effective marginal price of zero. (This is because EPA proposes that "a unit's new unit set-aside allocation initially equals that unit's emissions for the control period … in the preceding year" (p. 371).) Doesn't this provide an underincentive for new units to control emissions? The same issue also arises for the allocations to new units in subsequent control periods, which the Preamble also explains poorly.

This discussion raises a number of questions:

- To the extent that EPA bases new unit allocations in a given period on a unit's emissions in the prior control period, how can EPA avoid effectively eroding the incentive for new units to reduce their emissions?
- To the extent that units receive more allowances in future periods as a result of increased emissions in a current period, won't this create an incentive to overemit in early periods?
- Is there an alternative, more neutral approach that EPA could use instead?
- Can EPA provide a clearer description of the new unit allocation rule and a fuller explanation of the resulting incentive impacts?

(ii) For existing units, in the final rule EPA has revised its provisions regarding units that cease operation. At proposal, EPA proposed continuing to allocate allowances to units for six years after they ceased operation. In the final rule, EPA plans to reduce the window of time to four years. In explaining this change, EPA does not provide any discussion of the implication for incentives for retiring coal plants. By reducing the allocation of allowances to units that retire, EPA is increasing the incentive to keep those old plants operating – to the detriment of public health and other policy considerations.

- Can EPA explain its reasoning in greater detail and specifically address the impact on incentives to continue to operate aging coal plants rather than retiring them?

Finally, when will the unit-by-unit allocations be provided? When will the public and states see them?

<u>4. EPA should invest significant time in reevaluating and reconsidering the design of the assurance mechanism.</u>

EPA faces constraints as a result of the court's ruling in *North Carolina.* However, it appears the agency has not fully appreciated the extent to which its proposed assurance mechanism may limit trading. While agency staff have correctly pointed out concerns with alternatives, they have not fully considered concerns with their proposed approach. Moreover, the assurance mechanism is at the heart of the trading mechanism used to implement the Transport Rule, and its performance will have significant implications for future market-based mechanisms.

The primary problem with the assurance mechanism is that it will impose very tight and essentially arbitrary hard ceilings on emissions at the level of designated representatives. No DR will be able to emit more than 10 percent of its allocation without risking penalty. Because the allocations are essentially arbitrary (connected to past heat input) they do not bear any relation to actual emissions. That is okay from the perspective of allocation *per se*, but EPA does not discuss how the allocation decision interacts with the assurance mechanism.

- Has EPA done any analysis of how large the designated representatives are likely to be? On a call, EPA mentioned how many there might be per state; but this is a different question, namely what is the distribution of the number of units (and the diversity of fuel sources/emissions rates) in designated representatives?

- How do the allocations at the DR level compare to baseline emissions?
- Has EPA modeled the ability of individual units or DRs to comply with the allocation-plus-10-percent ceiling, using the allocations in the final rule?

As a result of this tight constraint, it seems likely that the assurance mechanism will severely limit trading. It is hard to imagine, for example, that a regulated utility would choose to comply by leaving its emissions uncontrolled and covering those emissions with purchased allowances, because that would leave it exposed to the risk of higher-than-expected emissions and a steep penalty.

- Has EPA considered the incentives facing regulated generators, including the likely treatment by PUCs of emission allowances, penalties, fuel-switching costs and so on? Has EPA considered the incentives facing regulated generators, including the likely treatment by PUCs of emission allowances, penalties, fuel-switching costs and so on?
- One potential response to these concerns might be that other concurrent EPA regulations are likely to end up requiring significant investment in advanced pollution control equipment at existing units anyway. Has EPA modeled the performance of the assurance mechanism taking other rules into account, such as MATS?

A second problem that EPA does not appear to have recognized is that the proposed assurance mechanism depends very heavily on the allocation mechanism used. It is designed specifically with EPA's proposed allocation rule in mind, since the penalties for individual units (or DRs) are based on their allocation plus the variability limit.

- How does EPA propose to implement the assurance mechanism under alternative allocation schemes that states might enact as part of their SIPs, such as allowance auctions?

Finally, EPA appears to have not fully appreciated how the assurance mechanism interacts with other enforcement provisions. EPA points out that a violation of the assurance mechanism will not constitute a violation of the Clean Air Act – presumably by way of reassuring people that the consequences of unexpectedly exceeding the emissions limit will be limited to a higher marginal price of emissions. However, EPA also specifies that "failing to hold sufficient allowances to meet the allowances surrender requirement [under the assurance mechanism] will be a violation of the regulations and the CAA" (p. 386). Effectively this means that entities will need to purchase and hold excess allowances in preparation for the potential eventuality that the assurance mechanism might be triggered and that their emissions might exceed their DR-level variability limit. In principle, an entity might wait until after a control period or even just before the "true-up" date to see whether extra allowances were needed; but in practice many entities have expressed a preference for managing their allowance holdings in a more continuous fashion, i.e., ensuring that they are accumulating allowances in line with their emissions. In that case, the threat of very steep penalties under the CAA may appear to be a real one, and entities contemplating compliance strategies that would put them at risk of triggering the assurance mechanism may act as if they face an effective marginal cost that is much greater than three times the allowance price.

- Has EPA considered how entities are likely to comply with the assurance mechanism given the prospect of full CAA enforcement for failing to hold sufficient allowances?

Again, the common theme is that EPA does not appear to have carefully thought through how the components of its scheme interact. While each of the components (the variability limits, the allocation rule, the assurance mechanism) may appear reasonable in isolation, in combination they appear very likely to stifle the development of an emissions market and undermine the scheme's cost-effectiveness. The complexities are compounded in regulated electricity markets, where compliance expenditures can be added to utilities' rate bases and earn a rate of return, whereas penalty payments most likely cannot.

- What has EPA done in the way of "worst-case" modeling to capture what might happen if the assurance mechanism effectively shuts down emission trading markets? Can EPA compare the cost of that scenario to the cost of other scenarios, such as one that only allowed intrastate trading (but in which intrastate trading was robust)?

During this review, we have discussed the possibility of the alternative mechanism proposed by commenters, with a parallel assurance market and interstate emissions trading market. EPA has chosen to reject this approach on two grounds: complexity and market power. The complexity argument is unpersuasive, for several reasons. First, the complexity could be reduced simply by allowing trading between Groups 1 and 2, as recommended above. That would cut the number of extra markets by 25 percent. Second, EPA appears to be understating the complexity of its proposed approach. Implementing the assurance mechanism in the final rule will require EPA to calculate allocations (or some equivalent benchmark in states that choose to use other allocation rules – see discussion above) at the DR level, compare those to actual emissions levels, and calculate the penalty. How is this easier and less complex than running a separate market?

Finally, EPA appears to be overstating the additional complexity of having separate assurance markets. Given automation and computing power, the costs of actually administering the markets are likely to be small. Moreover, although there may be startup costs associated with introducing an unfamiliar assurance market to utilities, those are fixed initial costs rather than ongoing ones. It is worth noting that EPA considered in its proposal having intrastate markets, and this would be no more complex to administer than that approach.

- Does EPA have actual experience or data it can point to support its concern that there will be large administrative costs associated with multiple markets? Can EPA explain in greater detail why its proposed approach is less complex?

The market power argument appears to hold more weight, but is worth digging into some more.

- Can EPA share its analysis of market power? Was this in one of the TSDs?
- How do the states in which market power would be a concern line up with the states that have regulated electric power sectors? Has EPA considered the ability of state regulators to address and mitigate market power considerations?
- In considering its intrastate approach, did EPA consider any design features that might limit market power, that might be applicable to the case of assurance markets?

In general, more careful thought needs to be given to alternatives, including the two-track market idea. In addition to its elegance and structural simplicity (which may or may not be offset by administrative complexity), the assurance market has three clear and important advantages. First, it would offer transparency and predictability for market participants, by providing a clear market-driven price signal of the likelihood that the state variability limits would be reached in a given year. Second, it could provide an ironclad assurance that state variability limits will be met, or alternatively could be tweaked for more flexibility if desired (e.g., by allowing states to sell additional assurance allowances at a set price, such as three times the market allowance price). Third, it can work independently of the particular allocation mechanism that a state uses to distribute emission allowances.

While the market power concern is worth considering, one can imagine addressing it through fairly simple design changes. For example, freely allocating the assurance allowances to individual units (e.g., on the basis of historical heat input) could help mitigate market power, since all units will have the option to hold onto their assurance allowances. Or, if (as suggested above) states were allowed to sell additional assurance allowances at a set price, the market power problem would be largely mitigated.

These comments are not meant to overemphasize the assurance market mechanism, which may not be the best approach. However, it appears EPA has done a much better job critically evaluating alternatives than it has done in looking squarely at the problems with its own approach. **More work is needed in this area.**

<u>5. EPA should consider allowing NOx allowances to be carried over into the Transport Rule program.</u>

Several reviewers believe that EPA appears to have strong grounds (given the *North Carolina* decision) for not accepting SO_2 allowances into the Transport Rule program (although we are still getting interagency comment, and on this point in particular we may want to have further conversations about this issue). However, its rationale is not as strong for NOx allowances. EPA defends its decision on the basis of three arguments: (1) the bank of CAIR NOx allowances is too large to be added to the state budgets calculated in the Transport Rule; (2) allocating unit-level Transport Rule allowances on the basis of banked CAIR allowances (e.g. by allowing banked allowance to be exchanged for Transport Rule allowances) would invite unacceptable legal risk by linking Transport Rule allocations indirectly to the fuel-factors approach used under CAIR and rejected by the court; and (3) allocating Transport Rule allowances on the basis of the CAIR bank would raise technical difficulties because of the time needed to determine final CAIR allowance holdings.

On the first of these arguments, it would be useful for EPA to share data on the provenance of the existing bank of CAIR NOx allowances, to help evaluate the argument that these represent "excess" emissions that should not be allowed. On interagency calls, EPA has said that a significant fraction of the outstanding allowances were excess or bonus allowances of some sort, but we haven't seen hard data on that. To the extent that they were simply carry-overs from the earlier NOx SIP Call, they could still represent legitimate early reductions.

- Can EPA share data on the existing bank of NOx allowances and how they were generated?

On the second argument, the legal risk does not seem particularly acute given that the current holders of allowances are not necessarily the same as the entities to whom the allowances were originally allocated.

- Can EPA provide data on that point, at least in the aggregate?

Moreover, even if the current banks largely reflect the original allocations, the court's ruling in *North Carolina* applied strictly to the question of how to allocate allowances among states, not among units within a state. Couldn't EPA allow for some (perhaps limited) exchange of banked NOx allowances without disturbing the state-level budgets calculated under the Transport Rule?

In addition, has EPA considered reviewing approved SIPs as a proxy for acceptable allowance banks? If approved SIPs do not include fuel adjustment factors, they should be carried over.

The third argument is important, but there might be a simple solution. What if EPA assigned unit-level allocations under the FIP for the 2012 control period, and then provided that existing banked NOx allowances could be exchanged for allowances in subsequent years? In other words, why can't EPA simply suspend the use of banked allowances for a year, rather than making them worthless?

The bottom line is that the principle of continuity in an emissions trading program should be of paramount importance, and EPA should seek to respect it unless there are very strong legal reasons preventing them from doing so. That appears to be the case for SO_2 allowances, but not for NOx allowances. The simple fact that there are a large number of banked NOx allowances is not grounds for eliminating them – to the contrary, it is something EPA should celebrate, since it represents early reductions made under previous programs. The existing rule gives lip service to the importance of continuity but honors it only in the breach.

Further, sunsetting the existing Title IV SO2 and CAIR banks in 2011 may likely set a bad precedent. Assigning no value to existing Title IV and CAIR emission banks because of their lack of future use will increase uncertainty in the value of any cap-and trade market from this Transport Rule or any other future rule, including any future CO2 cap-and-trade market. This rule has the potential to adversely affect all future cap and trade markets. EPA should give serious consideration to some method for pre-2012 allowance use.

This may also lead to perverse incentives and uncertain emissions for 2010. With the elimination of Title IV and CAIR allowances after 2011 and the complete loss of economic value to 2010 and 2011 allowances and their associated banks, the draft rule appears to cause the opposite of early emission reductions. Has EPA considered the perverse incentive created by a no carryover requirement, i.e., that holders of allowances may have an incentive to "dump" emissions before allowances expire?

6. EPA should consider the implication for other banked permits

Declining to carryover all CAIR allowances would also affect the Title IV allowance market (effectively rendering them valueless). Given this impact, EPA might still lawfully base the Transport pool of allowances on existing volume of banked Title IV allowances. This approach would be similar to that of the Compliance Supplement Pool (CSP) used in early NOx emissions programs transitions. The reference to the Title IV bank needn't be a full replication if the agency is concerned about the court's decision regarding the limits of Sec. 110(a)(2) authority in relation to Title IV markets. In addition, EPA has received public comment suggesting this approach. What is EPA's response to this approach?

7. Further interagency discussion of other trading mechanisms

The RIA discusses alternatives: one more stringent and one less stringent. But it does not discuss alternative trading mechanisms. Further, in order to know the benefits of allowing limited interstate trading, relative to the costs (especially the risk of there being no trading at all), we need to know how much the marginal abatement cost varies across states and within states. Has EPA made any attempt to estimate that and is it reflected in the rule or the RIA?

We would like greater discussion of the following:

1. Only intrastate trading allowed. This might have two disadvantages:
    a. Market power in smaller states. But market power leads to an inefficiently low number of trades, which would be preferred relative to zero trades.
    b. Numerous markets: one for each pollutant in every state. The complexity inherent in a multiplicity of markets would be offset by the simplicity of each one of the markets. Within markets, there would be no penalties, no uncertainty over what other utilities in the state do, no risk of exceeding assurances, etc. The preamble claims (p.280) that intrastate trading would be more resource intensive for sources, but it is not clear why that is true. The rule also claims that the intrastate only option would be less transparent. Again, that seems unclear.
2. Some version of the dual-track trading program mentioned during one of our phone calls. There would be state-specific permits and (fewer) interstate permits. Each ton of emissions would require one of each type of permit. No state could exceed its assurance level, because of the fixed number of state-specific permits. But utilities in states with low compliance costs could sell interstate permits to utilities in states emitting more (though still less than the assurance level). The market price of the state-specific permit would be zero in states selling the interstate permits, and positive in states buying the interstate permits.

B. FIP/SIP Structure

Many states requested that EPA put out a rule that will allow for states to submit SIPs and manage their own program as soon as possible. There was concern that EPA's timeline with Phase I starting in January, 2012, and Phase II starting in January, 2014, does not allow time for states to develop and submit SIPs to EPA. This in turn will mean that they will be subject to a FIP for a number of years, which may lead to higher costs/burden for both the state agencies and the regulated entities. This may also carry a legal risk.

- Has EPA considered other options for allowing great state control of this program, outside of what has been outlined in the draft final rule?
- For instance, has EPA considered eliminating Phase I and instead starting with Phase II?

As one commenter suggested, EPA cited the need for a Phase I requirement in order to assure there were sufficient allowances banked by Phase II, but they requested that EPA skip Phase I and instead add a CSP for Phase II.

C. Impact of CAIR

Could EPA provide an analysis where you utilize the emissions reductions due to the CAIR rule in projecting 2012 design values? Although this rule replaces CAIR, we are interested in seeing whether CAIR reductions have already alleviated some of the attainment and maintenance issues identified in this final rule. Further, has EPA considered utilizing CAIR outcomes (perhaps in conjunction with approved SIPs) as a more flexible approach to determining inclusion of transport states?

D. Electricity Price Modeling

The RIA examines the effects of the rule on electricity prices. What assumptions about trading are built into that estimate? For example, is the assumption that all market-clearing trades take place so long as they don't exceed state variability levels? If so, is that realistic? **If the complexities of the assurances and penalties result in there being no trading, what would be the effect on electricity prices?**

E. Timing/Transition

It is unclear if states and affected facilities will be prepared for a January 1, 2012 start date, especially given other changes that EPA is making in the draft final rule. For instance, **modeling results used in the final rule are substantially different than those in the original August 2, 2010 Proposed Rule and subsequent notices.** Six (6) States are being dropped from the proposed rule; Texas is being added; 3 States have their SO2 Group status change; and the sheer magnitude of change to the budgets of all of the states results in a significantly different rule than originally proposed.

In the sixteen (16) States where the EPA reduced SO2 emission budgets for 2012, the reduction in the State's trading budgets are dramatic - ranging from 2% to 69% and averaging 26%.

Similar issues are evident with the 2014 SO2 State trading budgets. Budget reductions range from 7% to 72% with an average of 26% in the 19 affected states. The Tennessee 2014 SO2 budget has been reduced by 41%.

For Annual NOx budgets, sixteen (16) States face budget reductions of 2 to 40% with an average of 18% for the 2012 budget. In 2014, seventeen (17) States face budget reductions of 4% to 50% with an average of 23%. In Tennessee the annual 2014 NOx budget has been reduced by 32%.

EPA has not provided details that would show what site-specific controls/measures the agency's modeling indicates would be necessary to eliminate a State's significant contribution.

Further, accelerating the date the assurance provision becomes effective from 2014 (in the proposed rule) to 2012 (latest interagency draft), greatly changes compliance planning for 2012 and 2013. Such a substantial change occurring six month prior to the effectiveness of the assurance provision leaves sources with few options to respond in a cost-effective manner, increasing the likelihood of disrupting system reliability if it becomes necessary to achieve compliance through derates and/or idling. Can EPA explain why they are accelerating the assurance provision effective date?

Units may have to be idled to meet allocation caps until controls are installed thereby increasing costs and decreasing reliability.

EPA control installation schedules do not account for accessibility to construction sites at existing plants. EPA's examples of rapid control equipment installations were at sites with good access around the units allowing rapid construction of new controls. These are atypical of most installations.

Controls needed to achieve reductions under the TR rule would be very site specific due to varying unit designs, fuels burned, and generation requirements (capacity factor, etc.) Accordingly, site specific detailed designs would be necessary, increasing the time necessary to achieve the reductions. The EPA schedule doesn't allow adequate time for project planning, scope development and detailed design. EPA received comments on this issue, and others related to the estimated construction time in its modeling. Further information can be provided on this issue, for the SCR and FGD lead time assumptions.

- Did EPA make any changes to its estimated construction times?
- How do longer equipment installation times affect the achievement of the current limits? Has EPA done any sensitivity analysis on these assumptions? Was this part of a reliability assessment?

F. Technology Concerns

EPA estimates that one third (3 GW) of the SO2 reduction technology installed to meet the Transport Rule are projected to be dry sorbent injection (DSI). Nearly all of the 5.9 GW of FGD retrofits are comprised of 12 units at 7 plants. We believe that the number of FGDs that may be necessary to meet the TR reductions may have been underestimated. It is unlikely that reliance on lower sulfur coals and on dispatch of lower-emitting generation units alone can achieve these reductions, setting aside the technical problems involved with switching to lower sulfur fuels.

DSI adoption is assumed to occur at an SO2 price of $2,300/ton. FGD assumed to be built at $1,600/ton. This set of assumptions is at odds with those made in the utility MACT rule, where DSI was viewed as a less expensive control option than FGD. Please clarify.

Utilities must plan controls to meet all anticipated regulatory requirements including the proposed Utility MACT. To this end, the TR proposal's reliance on DSI is unwarranted. It would not be prudent to install a technology (DSI) to meet the reductions required under the Transport rule if a different technology (FGD) may be necessary to meet the standards of the Utility MACT. Required controls for MACT are anticipated to be more complex and require longer construction cycles than what EPA is anticipating for the Transport Rule. Also the proposed MACT is still subject to change. For example, since the proposed rule was published in the Federal Register on May 3, 2011, EPA has announced a change to the mercury limit for existing sources by 20%. Moreover, the alkali injection assumption for DSI technology may not work with high sulfur coal. Likewise, there are concerns about water issues from sodium when Trona is used for duct sorbent injection for SO2 control. Even if these unresolved issues with DSI technology did not exist, the use of this technology carries the risk that it may become a stranded investment in light of the stricter standards in the later MACT rule.

Finally, For dry sorbent injection, what type of system or sorbent is actually used in the IPM modeling? For the LNB/OFA improvements, how many units (GW capacity) are installing new low-NOx burners and how many units are installing existing combustion control improvement? What has EPA assumed for improvements, i.e., the type of improvements and NOx reduction levels?

We suggest EPA should increase their prediction of the number of FGD's that may be required and included the cost and schedule increase in their estimates of the rule impacts. The 2014 deadline in the TR rule should be dovetailed with the compliance deadline in the MACT rule, consistent with the statutory standard to install controls as expeditiously as practicable. Further, the assurance provision should become effective on this deadline for meeting the MACT standards.

G. Reliability Concerns

EPA suggests shifts in generation where controls cannot be installed in time without considering transmission constraints. For instance, such constraints exist at several TVA plants and are particularly severe at TVA's Shawnee plant (Kentucky) where more unit retirements may be required than predicted by EPA.

Recommendation: EPA should include the time required for transmission upgrades and/or construction of replacement transmission lines in their schedule for compliance and capture the associated costs.

H. Regional Haze

Please clarify relationship of this rule to the Regional Haze Rule. Since EPA determined that the emissions reductions under the original CAIR would achieve greater emissions reductions than the Best Available Retrofit Technology requirements of the regional haze rule, regional haze SIPs submitted by many eastern states have cited EPA's determination rather than performing source specific BART analyses for electric generating units. As requested by commenters, EPA should consider demonstrating/determining that emissions reductions under the proposed transport rule will also be better than BART for both SO2 and NOx or states will need to revise their regional haze SIPs to include source specific BART analyses. It is not clear why EPA is not making that finding in this draft final rule.

I. Future Transport Rule

EGUs account for only 14% of nationwide NOx. Why is EPA planning to do another Transport rule for these sources in the future when there may be more cost-effective NOx tons to be reduced?

Exhibit H

VIA ELECTRONIC MAIL AND FIRST CLASS MAIL

September 20, 2011

Administrator Lisa P. Jackson
USEPA Headquarters
Ariel Rios Building
1200 Pennsylvania Avenue, N. W.
Mail Code: 1101A
Washington, DC 20460

Re: SPP's Review of the EPA's IPM Analysis of the Cross-State Air Pollution Rule, Docket ID No. EPA-HQ-OAR-2009-0491

Dear Ms. Jackson:

Southwest Power Pool, Inc. (SPP), in its capacity as a Federal Energy Regulatory Commission (FERC) approved Regional Transmission Organization (RTO) and a Regional Entity, is concerned that the Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR) without adequately assessing the reliability impacts of the CSAPR on the SPP region. SPP originally expressed concern with the reliability impacts of proposed regulations[1] in its July 19, 2011 comment letter to the EPA.

As required by the Energy Policy Act of 2005, FERC has approved mandatory and enforceable reliability standards promulgated by NERC with which the industry must comply. These standards were developed through a well vetted industry process identifying key requirements to ensure the bulk electric system meets an adequate level of reliability. Failure to comply with these standards can affect the ability of the power grid to operate reliably as well subject SPP and its members to financial penalties. These standards require that SPP's Transmission Planners ensure that transmission lines are not overloaded and that voltage is maintained within certain prescribed limits in the event of the failure of a single element in the system. Additionally, the standards require that Transmission Operators operate in real-time within certain limits. In order to meet the demands of the system there needs to be an adequate balance of generation and transmission availability both in the short and long term. The timing of the CSAPR regulations does not provide the SPP region with enough time to ensure that adequate balance.

Our reliability modeling[2] indicates that the CSAPR Integrated Planning Model 4.1 (IPM) results, as depicted by the EPA, are likely to cause SPP to be out of compliance with the applicable NERC standards as early as 2012. SPP's planning models identified 5.4 GW from the 48 generation units identified by the EPA with zero fuel burn in 2012 that would have been dispatched during the 2012

[1] On July 19, 2011, Nicholas A. Brown, SPP President and CEO, submitted comments to the EPA in Docket ID Nos. EPA-HQ-OW-2008-0667, EPA-HQ-OAR-2009-0234, and EPA-HQ-OAR-2011-0044, additionally providing SPP's preliminary assessment of the potential reliability impacts of proposed EPA regulations impacting generation in the SPP footprint.
[2] SPP removed all generation units in its models that consumed zero fuel in the EPA models. No other SPP model adjustments were made.

Summer Peak conditions. Our analysis revealed 220 overloads in excess of the required, 100% of emergency ratings under contingencies, and 1047 circumstances at various locations on the transmission system where voltage was below the prescribed lower limit of 90% of nominal rating. The statistics in this analysis must be viewed as being indicative, not definitive, results and are probably very conservative compared to what would be experienced in the real world should the modeled system conditions exist. An even clearer representation of reliability violations can be found by applying higher operability limits of 120% to the overloads. There were 16 such overloads on the system. Using a similar out of normal range there were 93 circumstances where voltage dropped below 85% of nominal. These "clear-cut" examples of standards violations represent the well founded concerns regarding the timeline with which the CSAPR would be instituted.

Additionally, 30 contingency scenarios did not solve, which is indicative of extreme system constraints, including the potential of cascading blackouts similar to what occurred in 2003 or which could require the shedding of firm load (that is, localized rolling black-outs initiated by utilities within the SPP region) to avoid more widespread and uncontrolled blackouts and to remain in compliance with reliability standards. Some of the contingencies could be resolved with other short-term transmission and/or resource solutions, but several could not. In those cases, SPP would be in clear violation of mandatory reliability standards and subject to penalty from FERC. However, SPP cannot be compliant with NERC's planning standards without placing its generation owners in violation of EPA standards when the unutilized units in the IPM are unavailable to SPP. Further exacerbating this situation, SPP's analysis also revealed that generation production from "small units"[3] increased from 13 to 57 units deployed. Some of these units are likely subject to the reciprocating internal combustion engines (RICE) regulations, which were not evaluated as part of this reliability study. If we look beyond the summer peak hour studied, the unavailability of approximately 11 GWs[4] of total capacity from the EPA model in SPP's footprint would likely result in additional localized reliability issues.

The result of SPP's reliability assessment of the EPA's CSAPR IPM generation dispatch indicates serious, negative implications to the reliable operation of the electric grid in the SPP region raising the possibility of rolling blackouts or cascading outages that would likely have significant impacts on human health, public safety and commercial activity within SPP. These regulations further compound the reliability impacts addressed by SPP in its July 19, 2011 comment letter, which focused on the MACT regulations to be enacted in 2014/15. The time period between finalization of the CSAPR and its effective date is too short to allow SPP and its members/registered entities to appreciate the effects of the rule and to take actions to ensure reliability.

SPP supports a more flexible approach to meeting the emission requirements under the CSAPR, as stated in a joint letter from the New York Independent System Operator, Midwest Independent System Operator, PJM Regional Transmission Organization, the Electric Reliability Council of Texas, and SPP to the EPA in August. The EPA must provide time to allow the industry to plan an approach to comply with its rules in a reliable and reasonable fashion. As it stands now, SPP and its members may be placed in the untenable position of deciding which agency's rules to violate, FERC or EPA. Putting an

[3] "Small units" denotes those units generating 25 megawatts or less per unit.

[4] Although the EPA model had additional units and capacity with zero fuel burn in 2012 (10.7 - 10.9 GW in total depending on the source of the Pmax), many of these units which were not dispatched in our 2012summer model will be needed during off-peak load periods to accommodate outages and to maintain system reliability.

industry with critical infrastructure in the position of choosing which agency's rules to violate is bad public policy. SPP suggests that the EPA delay CSAPR's effective date at least a year to allow for investigating, planning, and developing solutions to assist our members in maintaining grid reliability and compliance with both its current regulatory bodies and all of the EPA regulations that impact the electric industry.

Your prompt attention to this matter is greatly appreciated. Please do not hesitate to contact me if you have any questions or would like to discuss this matter further.

Respectfully submitted,

Nicholas A. Brown
President & CEO
Southwest Power Pool, Inc.
(501) 614-3213 • Fax: (501) 664-9553 • nbrown@spp.org

John Meyer
Chairman and Trustee
Southwest Power Pool Regional Entity

David Christiano
Trustee
Southwest Power Pool Regional Entity

Gerry Burrows
Trustee
Southwest Power Pool Regional Entity

cc: SPP Board of Directors
SPP Regional State Committee
SPP Strategic Planning Committee
State Regulators in Arkansas, Kansas, Louisiana, Missouri, Mississippi, Nebraska, New Mexico, Oklahoma, and Texas

Southwest Power Pool

HELPING OUR MEMBERS WORK TOGETHER
TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE

Congressional Delegations of Arkansas, Kansas, Louisiana, Missouri, Mississippi, Nebraska, New Mexico, Oklahoma, and Texas
Governors of Arkansas, Kansas, Louisiana, Missouri, Mississippi, Nebraska, New Mexico, Oklahoma, and Texas
North American Electric Reliability Corporation
President Barack Obama
Secretary of Energy Dr. Steven Chu
Federal Energy Regulatory Commission

415 NORTH MCKINLEY STREET, SUITE 140 | LITTLE ROCK, AR 72205 | 501-614-3200 | SPP.ORG

Exhibit I

Entergy

Entergy Services, Inc.
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The Woodlands, TX 77380
Tel. 281-297-3306
Fax 281-297-3251

Myra Glover
Director, Fossil Environmental, Health and Safety

September 20, 2011

Mr. Jeb Stenhouse
Branch Chief, Program Development, Clean Air Markets Division
U.S. EPA
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Mail Code: 6204J
Washington, DC 20460

Dear Mr. Stenhouse:

Thank you for the opportunity to provide additional information about the Entergy Electric System that supports adjustments to the Cross-State Air Pollution model to recognize local transmission constraints and other considerations. The attached document addresses two issues and presents a recommendation for each. First, the Cross-State Air Pollution model overstates the Entergy Transmission System's ability to transmit capacity and/or energy to and from neighboring systems. We have already discussed this issue, but it is summarized on the attached document for your convenience. Second, the Cross-State Air Pollution model does not reflect constraints of certain sub-regions of the Entergy Transmission System which require special consideration from both a planning and operations standpoint. The document provides additional information about each of these sub-regions that is intended to be meaningful and supportive of EPA's additional consideration, but, as we also have discussed, reflects the extreme sensitivity of this information.

I appreciate EPA's consideration of this information. If you have any questions or would like to discuss further, please do not hesitate to call.

Sincerely,

Myra Glover

Myra Glover
Entergy Services, Inc.

Attachment

Entergy Transmission System Consideration for the Cross-State Air Pollution Rule

9/20/2011

I. Overview

The Entergy Electric System includes service to customers within Arkansas, the western area of Mississippi, the far eastern portion of Texas, and a majority of the state of Louisiana. The Entergy Transmission System is comprised of a transmission network with operating voltages from sub-transmission levels of 69 kV, high voltage ("HV") levels of 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, and extra-high voltage ("EHV") levels of 500 kV. Voltages operating up to 230 kV primarily are utilized for local load-serving capability. The 500 kV network and a relatively limited amount of 345 kV transmission allows some flexibility to move larger blocks of capacity and/or energy internally within the Entergy Transmission System. In many local areas, the EHV system is utilized to provide a "source" of energy to the underlying HV load serving networks via transformer connections, such as "autotransformers" or "step-down transformers."

II. Transfer Capability Among Regions

The Entergy Transmission System's tie-lines with its neighboring transmission systems have the ability to transmit a limited amount of capacity and/or energy to and from neighboring systems. Historically the ties were constructed and operated to allow both economic or emergency capacity to be provided and energy to be moved between the Entergy Region and neighboring transmission systems. The Entergy Transmission System, like all transmission systems, has congestion that limits its ability to transfer power to and/or from other regions at some times and under some circumstances. The transfer capability afforded by the interconnections between regions is reviewed in both near-term and long-term studies on an annual basis; however, the results of these studies are considered confidential Critical Energy Infrastructure Information ("CEII") and are not made public. The results of these studies are reported through the reliability regions and ultimately to North American Electric Reliability Corporation ("NERC"). On occasion, publicly available studies are performed. A recent ongoing study that provides some useful information for the Entergy Region, including Arkansas Electric Cooperatives, Inc., can be found in preliminary work being performed by the Eastern Interconnection Planning Collaborative ("EIPC"). The EIPC, which includes Planning Authority ("PA") representatives from the majority of PA's in the Eastern Interconnection ("EI") (the electric grid connecting most of the eastern and mid-western United Sates, minus most of Texas), was selected by the Department of Energy to perform a study to analyze the potential transmission requirements needed to address various stakeholder-selected future scenarios. As part of the study requirements, a future year 2020 PA roll-up transmission load flow case was prepared that included the PA's most recent 10-year plans. For the Entergy Electric System, the majority of projects included were associated with reliability requirements for the year 2020. The stakeholders involved in the study process elected to remove certain facilities from the case that stakeholders considered to be less certain to be operating by 2020. The load flow case was then analyzed to determine the First Contingency Incremental Transfer Capability ("FCITC") limits that would be expected between the various regions in the year 2020. These limits were then established as the base transfer capability between the various regions in the EI. The levels indicated in the EIPC information should be considered as indicative of the order of magnitude of non-simultaneous transfers that may be available. It should be noted that non-simultaneous transfer capability, i.e. summing up transfer capabilities from multiple delivery points or regions into a single delivery point or region, is not indicative of a region's ability to import energy. It should also be noted that the sum of the non-simultaneous transfers calculated is not equivalent to the simultaneous transfer capability when considering the ability to import or export into all connected regions at the same time.

The EIPC study results indicate that the *non-simultaneous transfer* capability between regions external to the defined Entergy Region exist at a significantly lower level than that assumed in EPA's Integrated Planning Model, and these lower levels are more consistent with values that have been seen in near-term calculations. Entergy proposes that EPA consider using these FCITC values as a proxy to the Cross-State Air Pollution model to reflect more accurately the limited ability to move large blocks of energy and capacity from one region to another. Even these projections likely overstate the current ability to transfer power, because the values include future transmission improvements that have not been constructed or placed in service. In addition, Entergy encourages EPA to utilize a *simultaneous transfer* capability in order to determine the ability of the interconnected transmission system realistically to accommodate imports into a specific region. Entergy has provided the results of the EPIC study to EPA previously. For your convenience, results relevant to the Entergy Region are summarized in Table 1 below.

Table 1

Transfer Limits between North American Electricity and Environment Model (NEEM) Regions (MW limits)

	Destination	Origin
	ENTERGY	ENTERGY
ERCOT		
FRCC		
MAPP_CA		
MAPP_US		
MISO_IN		
MISO_MI		
MISO_MO_IL	2,540	2,260
MISO_W		
MISO_WUMS		
SOCO	2,400	2,000
SPP_N	1,800	1,300
SPP_S	850	1,300
TVA	3,000	2,100

= Non-existent links

ENTERGY	MISO_MO_IL	To obtain the MRM-NEEM Pipe Transfer Limit between MISO and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between MISO and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies. Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
ENTERGY	SOCO	To obtain the MRM-NEEM Pipe Transfer Limit between Southern Company and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between Southern Company and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
ENTERGY	SPP_N	To obtain the MRN-NEEM Pipe Transfer Limit between SPP and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then coordinated between SPP and Entergy.

ENTERGY	SPP_S	To obtain the MRN-NEEM Pipe Transfer Limit between SPP and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then coordinated between SPP and Entergy.
ENTERGY	TVA	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between TVA and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies.

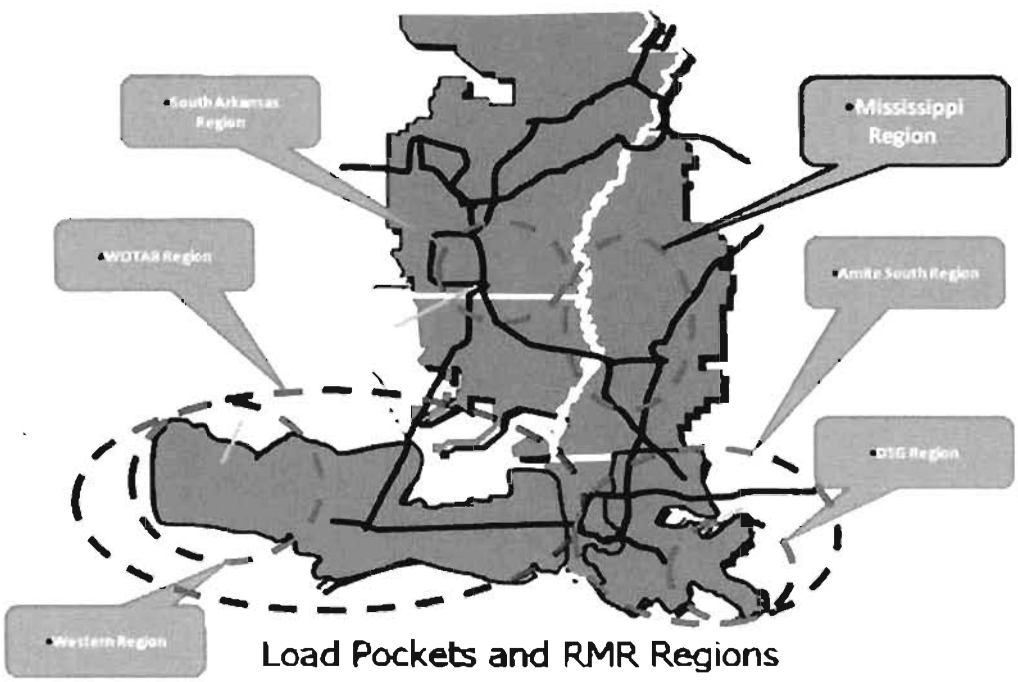
III. <u>**Sub-region Constraints**</u>

The historical development and geographical features of the Entergy Electric System have resulted in certain sub-regions being defined as "load pockets" from both a planning and operations standpoint. Load pockets are areas of the system which must be served in part by the transmission system, but are also dependent on local generation to serve the entire load within the load pocket. Over time, the number of defined load pockets considered in reliability analyses may be increased or decreased depending on future load forecasts, generation additions or deactivations, and subsequent transmission system changes.

Figure 1, below, indicates the primary sub-regions of the Entergy Transmission System that are taken into special consideration from both a planning and operations standpoint. These areas include the West of the Atchafalaya Basin ("WOTAB") Region, the Western Region, the Amite South Region, the Downstream of Gypsy ("DSG") Region, the Mississippi Region, and the South Arkansas Region.

Figure 1

Load Pockets and Reliability Must Run Sub-regions of the Entergy Transmission System



Source: Based on the study area map in the Entergy Regional State Committee Minimizing Bulk Power Cost Study, August 24, 2011

The historical evolution and development of the Entergy Transmission System has resulted in a system comprised of local generation and transmission serving sub-regions of the Entergy system, linked together by the EHV grid. Reliable operation of the Entergy Electric System relies on the close coordination of the power generated by the local generation stations and the available internal transmission capability to move energy and capacity reliably between sub-regions of the Entergy Transmission System. The sub-regions requiring special planning and operations considerations are described below, followed by recommended inputs for consideration in EPA's Cross-State Air Pollution model to recognize the described local conditions.

The West of the Atchafalaya Basin ("WOTAB") Region

The WOTAB Region is a geographical area bounded to the east by the Atchafalaya Basin; to the north by the CLECO transmission system; to the south by the Gulf of Mexico; and to the west by ERCOT. Based on the inherent transmission configuration within the region, there are Reliability Must Run ("RMR") requirements for generation facilities in both the Lake Charles area of Louisiana and the Port Arthur area of Texas. The WOTAB Region, which only has two 500 kV transmission lines along with a single 345 kV line in the far west end, is very dependent on the local generation in both Lake Charles and Port Arthur to help maintain the reliability of the Entergy Transmission System. Additionally, the WOTAB Region has a large concentration of industrial loads; consequently, the region is dependent on local generation not only to provide active (MW) support to the area but also reactive (MVAR) support to help maintain adequate voltages and voltage stability to the region.

RMR requirements of the generation units in this region generally are triggered by thermal constraints associated with some non-EHV facilities on the eastern side of the region, and voltage constraints that are observed under contingency in regions of heavy load concentration within WOTAB. The generation units associated with the RMR requirements include Nelson Units 3 and 4 in the Lake Charles area and all of the Sabine Units (1 – 5) in the Port Arthur area.

The Western Region

The Western Region is a defined load pocket within the WOTAB Region. It encompasses the westernmost portion of the WOTAB Region and is defined generally as west of the Trinity River, including the load centers in The Woodlands and Conroe, Texas. The major transmission sources of power serving this area include five 138 kV lines, two 230 kV lines, and one 345 kV line. The available generation resources within this area include Lewis Creek Units 1 and 2, one merchant generating facility, and an electric cooperative owned generating facility. Due to the relatively high load-to-generation ratio within this load pocket, the Entergy Transmission System is planned to withstand the loss of one Lewis Creek Unit (assuming the other Lewis Creek Unit also is committed) and a transmission line within the Western Region load pocket. It should be noted that the geographical location of the Western Region is very similar to a peninsular configuration -- it is very dependent on the ability to import capacity and energy over the Entergy Transmission System from the east. The western border of this area is adjacent to the ERCOT system, but there are no synchronous tie-line connections with ERCOT. Due to the limited amount of transmission capability into the area, the local generating units in the Western Region have been designated RMR units. The commitment levels of these RMR units are triggered at various load levels of the Western Region to address thermal transmission loadings on the HV system associated with the loss of key 230 kV lines. Additionally, the voltage support afforded by local generation is taken into consideration to help maintain adequate voltage levels at the load centers.

The Amite South Region

The Amite South Region is a defined load pocket and encompasses most of southeast Louisiana. To the west, it starts at the Entergy Gulf States LLC and Entergy Louisiana LLC-South border. It continues to the east and north to the Louisiana – Mississippi border, north of Lake Pontchartrain. The southern end of the load pocket is bordered by the Gulf of Mexico. Under normal operating conditions, generating resources within this area, along with limited power imports from outside the Amite South Region, are relied upon to serve the local load. Due to the system configuration and the location of load, the imported power flows through a corridor of transmission tie lines that connect the Amite South Region to the rest of the Entergy Transmission System. The transmission capability of these ties-lines effectively establishes the Amite South Region's capability to import power.

Entergy-owned generation units that generally are committed in the area include not only Ninemile Units 3, 4, and 5, and Michoud Units 2 and 3, but also other units in the Amite south load pocket including Little Gypsy Units 1, 2, and 3 and Waterford Units 1 and 2. A primary concern for the area is the unavailability of the large Waterford Nuclear Unit. Without the commitment of other units located in the Amite South Region, the area is dependent on the transmission infrastructure to be able to import energy and power reliably into the area. Potential constraints can occur on the transmission system within the Amite South Region, but also in areas adjacent to the Amite South Region as the import requirements are increased. The facilities of concern include both transmission lines and 500 kV autotransformer capabilities.

The Downstream of Gypsy ("DSG") Region

The DSG Region is a defined load pocket within the Amite South Region. It encompasses all of the Entergy New Orleans, Inc. service territory as well as other Entergy service territories downstream of the Little Gypsy generating facility. Due to the relatively high load-to-generation ratio within this load pocket, the Entergy Transmission System is planned to withstand the loss of a single large DSG Region unit (assuming one of the other large units also is committed) and a transmission line. RMR commitment levels have been established based on thermal constraints within the DSG Region and also based on the need for reactive (MVAR) support from local generation to support area voltages. The Entergy units that need to be committed for RMR purposes in this area include Ninemile Units 3, 4, and 5, along with Michoud Units 2 and 3. The commitment of these units helps provide injections of local MW into the area, which in turn reduces the loadings on the transmission facilities feeding into the DSG Region. Likewise, the local generation provides dynamic voltage support to the area to help address voltage stability concerns in this area.

The Mississippi Region

The Mississippi Region RMR requirements are triggered by constraints observed in the general area located around the Jackson metropolitan area. At certain load levels and in the absence of any local generation, the loss of a key 500 kV autotransformer will cause other 500 kV autotransformer facilities to exceed their thermal ratings. RMR requirements have been established for this area and are triggered by Entergy Mississippi, Inc. (EMI) load levels. The RMR unit of consideration for this area is Rex Brown Unit 4.

In addition, two units, Gerald Andrus and Baxter Wilson, are not only critical in serving local load within EMI, but also in producing power counterflow that allows efficient combined cycle units in northern Louisiana and central Mississippi to generate. Loss of certain EMI generating units, as modeled by EPA, could reduce the ability to dispatch low emission CCGT units such as Perryville, Ouachita, and Attala, thus reducing flexibility to respond to load demand and producing a result antithetical to the goal of the Cross-State Air Pollution Rule. The negative impact will be felt across the Entergy Transmission System, as well as TVA and Southern systems.

The South Arkansas Region

The RMR requirements for the South Arkansas Region are driven by certain local constraints. At certain load levels, the loss of transmission facilities, including key 500 kV facilities, will result in underlying HV facilities and 500 kV autotransformer facilities exceeding their thermal ratings. Additionally, the loss of the 500 kV facilities (autotransformers) will cause low voltages to occur in the area in the absence of local generation being committed and on-line. RMR requirements to address this region are triggered by Entergy Arkansas, Inc. load levels. The primary unit of consideration for this area is the Arkansas Electric Cooperative Corporation's McClellan Unit.

Entergy encourages EPA to use the expected, unit-specific average capacity factors and fuel usage for the May 1, 2012 to September 30, 2012 time period presented in Table 2 to adjust the outcomes of the EPA Cross-State Air Pollution models. The average capacity factors and the associated fuel utilization estimate reflect the unit operation to meet Entergy Transmission System reliability and local load requirements described above.

Table 2

2012 Projected Ozone Season Unit Operation of Entergy Reliability Critical Units

Unit	Average Monthly Capacity Factor (%)	Total Natural Gas Usage mmBTU
Lewis Creek 1	46.6%	4,301,923
Lewis Creek 2	54.8%	4,968,032
Sabine 1	37.0%	3,155,208
Sabine 2	29.5%	2,598,981
Sabine 3	31.7%	5,077,359
Sabine 4	45.3%	8,918,197
Sabine 5	15.3%	3,298,070
Nelson 3	16.3%	1,067,708
Nelson 4	23.4%	4,606,952
Ninemile 3	10.9%	714,575
Ninemile 4	30.5%	9,528,484
Ninemile 5	34.0%	9,917,183
Michoud 2	29.8%	2,697,734
Michoud 3**	44.9%	7,546,917
Little Gypsy 1	6.7%	1,086,061
Little Gypsy 2	3.3%	1,010,463
Little Gypsy 3	23.8%	5,645,451
Waterford 1	3.4%	1,221,822
Waterford 2	7.0%	1,601,183
Rex Brown 4	4.1%	457,362
Gerald Andrus	33.4%	9,316,568
Baxter Wilson 1	7.0%	1,476,722
Baxter Wilson 2	18.1%	5,180,466
McClellan	16.4%	1,018,797

**Michoud 3 average capacity factor reflects the June 2012 to September 2012 time period because of a May 2012 scheduled maintenance outage.

Source: 2012 Entergy Business Plan, Budget Forecast Case

Exhibit J

Entergy

Entergy Services, Inc.
10055 Grogans Mill Road
Suite 400
The Woodlands, TX 77380
Tel. 281-297-3306
Fax 281-297-3251

Myra Glover
Director, Fossil Environmental,
Health and Safety

September 29, 2011

Mr. Jeb Stenhouse
Branch Chief, Program Development, Clean Air Markets Division
U.S. EPA
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Mail Code: 6204J
Washington, DC 20460

Dear Mr. Stenhouse:

Thank you for the opportunity to provide additional information about the Entergy Electric System in support of adjustments to the Cross-State Air Pollution model to recognize the affect of local transmission constraints and other considerations. The attached document addresses two issues and presents a recommendation for each. First, the Cross-State Air Pollution model overstates the Entergy Transmission System's ability to transmit capacity and/or energy to and from neighboring systems. We have already discussed this issue, but it is summarized on the attached document for your convenience. Second, the Cross-State Air Pollution model does not reflect constraints of certain sub-regions of the Entergy Transmission System which require special consideration from both a planning and operations standpoint. The document provides additional information about each of these sub-regions that is intended to be meaningful and supportive of EPA's further consideration of the various state budgets.

I appreciate EPA's review of this information. If you have any questions or would like to discuss further, please do not hesitate to call.

Sincerely,

Myra Glover

Myra Glover
Entergy Services, Inc.

Attachment

Entergy Transmission System Consideration for the Cross-State Air Pollution Rule

9/29/2011

I. Overview

The Entergy Electric System includes service to customers within Arkansas, the western area of Mississippi, the far eastern portion of Texas, and a majority of the state of Louisiana. The Entergy Transmission System is comprised of a transmission network with operating voltages from sub-transmission levels of 69 kV, high voltage ("HV") levels of 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, and extra-high voltage ("EHV") levels of 500 kV. Voltages operating up to 230 kV primarily are utilized for local load-serving capability. The 500 kV network and a relatively limited amount of 345 kV transmission allows some flexibility to move larger blocks of capacity and/or energy internally within the Entergy Transmission System. In many local areas, the EHV system is utilized to provide a "source" of energy to the underlying HV load serving networks via transformer connections, such as "autotransformers" or "step-down transformers."

II. Transfer Capability Among Regions

The Entergy Transmission System's tie-lines with its neighboring transmission systems have the ability to transmit a limited amount of capacity and/or energy to and from neighboring systems. Historically the ties were constructed and operated to allow both economic or emergency capacity to be provided and energy to be moved between the Entergy Region and neighboring transmission systems. The Entergy Transmission System, like all transmission systems, has congestion that limits its ability to transfer power to and/or from other regions at some times and under some circumstances. The transfer capability afforded by the interconnections between regions is reviewed in both near-term and long-term studies on an annual basis; however, the results of these studies are considered confidential Critical Energy Infrastructure Information ("CEII") and are not made public. The results of these studies are reported through the reliability regions and ultimately to North American Electric Reliability Corporation ("NERC"). On occasion, publicly available studies are performed. A recent ongoing study that provides some useful information for the Entergy Region, including Arkansas Electric Cooperatives, Inc., can be found in preliminary work being performed by the Eastern Interconnection Planning Collaborative ("EIPC"). The EIPC, which includes Planning Authority ("PA") representatives from the majority of PA's in the Eastern Interconnection ("EI") (the electric grid connecting most of the eastern and mid-western United Sates, minus most of Texas), was selected by the Department of Energy to perform a study to analyze the potential transmission requirements needed to address various stakeholder-selected future scenarios. As part of the study requirements, a future year 2020 PA roll-up transmission load flow case was prepared that included the PA's most recent 10-year plans. For the Entergy Electric System, the majority of projects included were associated with reliability requirements for the year 2020. The stakeholders involved in the study process elected to remove certain facilities from the case that stakeholders considered to be less certain to be operating by 2020. The load flow case was then analyzed to determine the First Contingency Incremental Transfer Capability ("FCITC") limits that would be expected between the various regions in the year 2020. These limits were then established as the base transfer capability between the various regions in the EI. The levels indicated in the EIPC information should be considered as indicative of the order of magnitude of non-simultaneous transfers that may be available. It should be noted that non-simultaneous transfer capability, i.e. summing up transfer capabilities from multiple delivery points or regions into a single delivery point or region, is not indicative of a region's ability to import energy. It should also be noted that the sum of the non-simultaneous transfers calculated is not equivalent to the simultaneous transfer capability when considering the ability to import or export into all connected regions at the same time.

The EIPC study results indicate that the *non-simultaneous transfer* capability between regions external to the defined Entergy Region exist at a significantly lower level than that assumed in EPA's Integrated Planning Model, and these lower levels are more consistent with values that have been seen in near-term calculations. Entergy proposes that EPA consider using these FCITC values as a proxy to the Cross-State Air Pollution model to reflect more accurately the limited ability to move large blocks of energy and capacity from one region to another. Even these projections likely overstate the current ability to transfer power, because the values include future transmission improvements that have not been constructed or placed in service. In addition, Entergy encourages EPA to utilize a *simultaneous transfer* capability in order to determine the ability of the interconnected transmission system realistically to accommodate imports into a specific region. Entergy has provided the results of the EPIC study to EPA previously. For your convenience, results relevant to the Entergy Region are summarized in Table 1 below.

Table 1

Transfer Limits between North American Electricity and Environment Model (NEEM) Regions (MW limits)

	Destination	Origin
	ENTERGY	ENTERGY
ERCOT		
FRCC		
MAPP_CA		
MAPP_US		
MISO_IN		
MISO_MI		
MISO_MO_IL	2,540	2,260
MISO_W		
MISO_WUMS		
SOCO	2,400	2,000
SPP_N	1,800	1,300
SPP_S	850	1,300
TVA	3,000	2,100

= Non-existent links

ENTERGY	MISO_MO_IL	To obtain the MRM-NEEM Pipe Transfer Limit between MISO and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between MISO and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies. Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
ENTERGY	SOCO	To obtain the MRM-NEEM Pipe Transfer Limit between Southern Company and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between Southern Company and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
ENTERGY	SPP_N	To obtain the MRN-NEEM Pipe Transfer Limit between SPP and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then coordinated between SPP and Entergy.

ENTERGY	SPP_S	To obtain the MRN-NEEM Pipe Transfer Limit between SPP and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then coordinated between SPP and Entergy.
ENTERGY	TVA	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between TVA and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies.

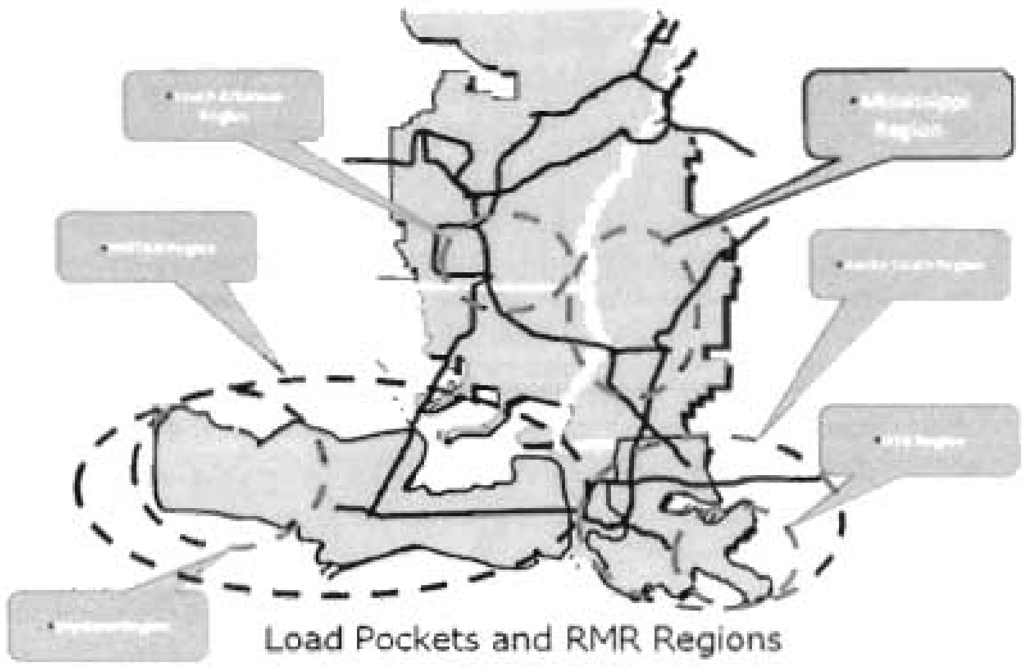
III. <u>Sub-region Constraints</u>

The historical development and geographical features of the Entergy Electric System have resulted in certain sub-regions being defined as "load pockets" from both a planning and operations standpoint. Load pockets are areas of the system which must be served in part by the transmission system, but are also dependent on local generation to serve the entire load within the load pocket. Over time, the number of defined load pockets considered in reliability analyses may be increased or decreased depending on future load forecasts, generation additions or deactivations, and subsequent transmission system changes.

Figure 1, below, indicates the primary sub-regions of the Entergy Transmission System that are taken into special consideration from both a planning and operations standpoint. These areas include the West of the Atchafalaya Basin ("WOTAB") Region, the Western Region, the Amite South Region, the Downstream of Gypsy ("DSG") Region, the Mississippi Region, and the South Arkansas Region.

Figure 1

Load Pockets and Reliability Must Run Sub-regions of the Entergy Transmission System



Source: Based on the study area map in the Entergy Regional State Committee Minimizing Bulk Power Cost Study, August 24, 2011

The historical evolution and development of the Entergy Transmission System has resulted in a system comprised of local generation and transmission serving sub-regions of the Entergy system, linked together by the EHV grid. Reliable operation of the Entergy Electric System relies on the close coordination of the power generated by the local generation stations and the available internal transmission capability to move energy and capacity reliably between sub-regions of the Entergy Transmission System. The sub-regions requiring special planning and operations considerations are described below, followed by recommended inputs for consideration in EPA's Cross-State Air Pollution model to recognize the described local conditions.

The West of the Atchafalaya Basin ("WOTAB") Region

The WOTAB Region is a geographical area bounded to the east by the Atchafalaya Basin; to the north by the CLECO transmission system; to the south by the Gulf of Mexico; and to the west by ERCOT. Based on the inherent transmission configuration within the region, there are Reliability Must Run ("RMR") requirements for generation facilities in both the Lake Charles area of Louisiana and the Port Arthur area of Texas. The WOTAB Region, which only has two 500 kV transmission lines along with a single 345 kV line in the far west end, is very dependent on the local generation in both Lake Charles and Port Arthur to help maintain the reliability of the Entergy Transmission System. Additionally, the WOTAB Region has a large concentration of industrial loads; consequently, the region is dependent on local generation not only to provide active (MW) support to the area but also reactive (MVAR) support to help maintain adequate voltages and voltage stability to the region.

RMR requirements of the generation units in this region generally are triggered by thermal constraints associated with some non-EHV facilities on the eastern side of the region, and voltage constraints that are observed under contingency in regions of heavy load concentration within WOTAB. The generation units associated with the RMR requirements include Nelson Units 3 and 4 in the Lake Charles area and all of the Sabine Units (1 – 5) in the Port Arthur area.

The Western Region

The Western Region is a defined load pocket within the WOTAB Region. It encompasses the westernmost portion of the WOTAB Region and is defined generally as west of the Trinity River, including the load centers in The Woodlands and Conroe, Texas. The major transmission sources of power serving this area include five 138 kV lines, two 230 kV lines, and one 345 kV line. The available generation resources within this area include Lewis Creek Units 1 and 2, one merchant generating facility, and an electric cooperative owned generating facility. Due to the relatively high load-to-generation ratio within this load pocket, the Entergy Transmission System is planned to withstand the loss of one Lewis Creek Unit (assuming the other Lewis Creek Unit also is committed) and a transmission line within the Western Region load pocket. It should be noted that the geographical location of the Western Region is very similar to a peninsular configuration -- it is very dependent on the ability to import capacity and energy over the Entergy Transmission System from the east. The western border of this area is adjacent to the ERCOT system, but there are no synchronous tie-line connections with ERCOT. Due to the limited amount of transmission capability into the area, the local generating units in the Western Region have been designated RMR units. The commitment levels of these RMR units are triggered at various load levels of the Western Region to address thermal transmission loadings on the HV system associated with the loss of key 230 kV lines. Additionally, the voltage support afforded by local generation is taken into consideration to help maintain adequate voltage levels at the load centers.

The Amite South Region

The Amite South Region is a defined load pocket and encompasses most of southeast Louisiana. To the west, it starts at the Entergy Gulf States LLC and Entergy Louisiana LLC-South border. It continues to the east and north to the Louisiana – Mississippi border, north of Lake Pontchartrain. The southern end of the load pocket is bordered by the Gulf of Mexico. Under normal operating conditions, generating resources within this area, along with limited power imports from outside the Amite South Region, are relied upon to serve the local load. Due to the system configuration and the location of load, the imported power flows through a corridor of transmission tie lines that connect the Amite South Region to the rest of the Entergy Transmission System. The transmission capability of these ties-lines effectively establishes the Amite South Region's capability to import power.

Entergy-owned generation units that generally are committed in the area include not only Ninemile Units 3, 4, and 5, and Michoud Units 2 and 3, but also other units in the Amite south load pocket including Little Gypsy Units 1, 2, and 3 and Waterford Units 1 and 2. A primary concern for the area is the unavailability of the large Waterford Nuclear Unit. Without the commitment of other units located in the Amite South Region, the area is dependent on the transmission infrastructure to be able to import energy and power reliably into the area. Potential constraints can occur on the transmission system within the Amite South Region, but also in areas adjacent to the Amite South Region as the import requirements are increased. The facilities of concern include both transmission lines and 500 kV autotransformer capabilities.

The Downstream of Gypsy ("DSG") Region

The DSG Region is a defined load pocket within the Amite South Region. It encompasses all of the Entergy New Orleans, Inc. service territory as well as other Entergy service territories downstream of the Little Gypsy generating facility. Due to the relatively high load-to-generation ratio within this load pocket, the Entergy Transmission System is planned to withstand the loss of a single large DSG Region unit (assuming one of the other large units also is committed) and a transmission line. RMR commitment levels have been established based on thermal constraints within the DSG Region and also based on the need for reactive (MVAR) support from local generation to support area voltages. The Entergy units that need to be committed for RMR purposes in this area include Ninemile Units 3, 4, and 5, along with Michoud Units 2 and 3. The commitment of these units helps provide injections of local MW into the area, which in turn reduces the loadings on the transmission facilities feeding into the DSG Region. Likewise, the local generation provides dynamic voltage support to the area to help address voltage stability concerns in this area.

The Mississippi Region

The Mississippi Region RMR requirements are triggered by constraints observed in the general area located around the Jackson metropolitan area. At certain load levels and in the absence of any local generation, the loss of a key 500 kV autotransformer will cause other 500 kV autotransformer facilities to exceed their thermal ratings. RMR requirements have been established for this area and are triggered by Entergy Mississippi, Inc. (EMI) load levels. The RMR unit of consideration for this area is Rex Brown Unit 4.

In addition, two units, Gerald Andrus and Baxter Wilson, are not only critical in serving local load within EMI, but also in producing power counterflow that allows efficient combined cycle units in northern Louisiana and central Mississippi to generate. Loss of certain EMI generating units, as modeled by EPA, could reduce the ability to dispatch low emission CCGT units such as Perryville, Ouachita, and Attala, thus reducing flexibility to respond to load demand and producing a result antithetical to the goal of the Cross-State Air Pollution Rule. The negative impact will be felt across the Entergy Transmission System, as well as TVA and Southern systems.

The South Arkansas Region

The RMR requirements for the South Arkansas Region are driven by certain local constraints. At certain load levels, the loss of transmission facilities, including key 500 kV facilities, will result in underlying HV facilities and 500 kV autotransformer facilities exceeding their thermal ratings. Additionally, the loss of the 500 kV facilities (autotransformers) will cause low voltages to occur in the area in the absence of local generation being committed and on-line. RMR requirements to address this region are triggered by Entergy Arkansas, Inc. load levels. The primary unit of consideration for this area is the Arkansas Electric Cooperative Corporation's McClellan Unit.

IV. <u>Transmission System Reliability and Local Load Requirement Impacts</u>

Entergy encourages EPA to adjust the outcomes of the EPA Cross-State Air Pollution models, taking into consideration the various Transmission System reliability and local load requirements described above. The information provided in Table 2 reflects the May 1, 2012 to September 30, 2012 forecasted unit operations for affected units dispatched by Entergy. The table includes projected capacity factors disaggregated into amounts necessary to support local transmission stability, resource deliverability and operational flexibility. In addition, projected fuel usage, minimum and maximum unit capability and the percent of on-line hours each unit is running at its minimum is included.

Table 2

2012 Projected Ozone Season Unit Operation of Entergy Reliability Critical Units

Constrained Region	Unit	Unit Max Capacity (MW)	Unit Minimum Capacity (MW)	Average Monthly Capacity Factor (%)	Local Stability Capacity Factor (%)	Resource Deliverability Capacity Factor (%)	Operational Flexibility Capacity Factor (%)	On-Line Hours at Minimum (%)	Total Natural Gas Usage mmBTU
Western	Lewis Creek 1	230	70	47%	24%	20%	2%	58%	4,301,923
Western	Lewis Creek 2	230	70	55%	24%	24%	7%	51%	4,968,032
WOTAB	Sabine 1	212	50	37%		17%	20%	37%	3,155,208
WOTAB	Sabine 2	212	50	30%		19%	11%	62%	2,598,981
WOTAB	Sabine 3	390	70	32%		16%	16%	54%	5,077,359
WOTAB	Sabine 4	525	185	45%	28%	15%	2%	47%	8,918,197
WOTAB	Sabine 5	470	55	15%	9%	4%	2%	78%	3,298,070
WOTAB	Nelson 3	130	25	16%		11%	5%	81%	1,067,708
WOTAB	Nelson 4	445	180	23%		20%	3%	66%	4,606,952
DSG	Ninemile 3	125	23	11%		8%	3%	84%	714,575
DSG	Ninemile 4	734	190	31%	19%	11%	1%	69%	9,528,484
DSG	Ninemile 5	740	210	34%	21%	12%	2%	61%	9,917,183
DSG	Michoud 2	235	40	30%		16%	14%	47%	2,697,734
DSG	Michoud 3**	529	180	45%	23%	21%	1%	55%	7,546,917
Amite South	Little Gypsy 1	238	18	7%		6%	1%	98%	1,086,061
Amite South	Little Gypsy 2	410	24	3%		3%	1%	97%	1,010,463
Amite South	Little Gypsy 3	522	150	24%		21%	3%	82%	5,645,451
Amite South	Waterford 1	411	32	3%		3%		100%	1,221,822
Amite South	Waterford 2	411	32	7%		6%	1%	94%	1,601,183
MS	Rex Brown 4	209	24	4%	4%			69%	457,362
MS	Gerald Andrus	712	260	33%		24%	9%	58%	9,316,568
MS	Baxter Wilson 1	500	160	7%		5%	2%	65%	1,476,722
MS	Baxter Wilson 2	676	190	18%		13%	5%	71%	5,180,466
AR	McClellan	136	30	16%	16%			100%	1,018,797

**Michoud 3 average capacity factor reflects the June 2012 to September 2012 time period because of a May 2012 scheduled maintenance outage.

The Local Stability Capacity Factor represents the amount of energy produced by a generator during the ozone season to meet the local area need for voltage support and local stability.

The Resource Deliverability Capacity Factor represents the amount of energy produced by a generator during the ozone season to meet the local area need for energy to meet the local reserves in the event of an unplanned transmission or generator outage or that cannot be met by out-of-region resources due to transmission import limits.

The Operational Flexibility Capacity Factor represents the amount of energy produced by a generator during the ozone season to meet the System and Local area need for flexible load-following resources.

Source: 2012 Entergy Business Plan, Budget Forecast Case

Exhibit K

Entergy Meeting w/ EPA to discuss Modeling Inputs

01 IPM Modeling Results for CSAPR - ETR with SPO review 8-29-11.xlsx

Entergy System Planning and Operations (SPO) staff reviewed a spreadsheet (Document 01) with IPM modeling results for CSAPR focused on the ENTG modeling region. SPO added a column (AK) with comments about some of the modeled units. Additionally, SPO highlighted certain rows as follows:

- Yellow – depicts a generation unit in the Entergy System that has some Reliability-Must-Run (RMR) requirements.
- Blue – depicts a QF generation unit that may not be as dispatchable as modeled because some generation serves that site's load.
- Red – depicts a generation unit that is inactive because of incomplete construction.

02 NEEM Transfer Limits Input Matrix FINAL 2-4-11.xlsx

03 NEEM Transfer Limits Input Descriptions FINAL 2-5-11.xlsx

Entergy is a participant in an Eastern Interconnect Planning Collaborative. Attached Document 02 summarizes non-simultaneous transfers for test year 2020 determined to be reasonable by the group and attached Document 03 provides a description of the modeling approach for each transfer path and validation activities.

04 100511 RMR Combined Scope 05112010.pdf

05 4c - August 2011ERSC MBPC Update.pptx

The Entergy Regional State Committee (E-RSC) provides collective state regulatory agency input on the operations of and upgrades to the Entergy Transmission System. The E-RSC is comprised of retail regulatory commissioners from agencies in Arkansas, Louisiana, Mississippi, Texas, and the Council of the City of New Orleans. Document 04 describes the scope of an E-RSC study to identify transmission projects that could reduce Entergy production costs related to the operation of RMR units. Document 05 is the most recent document describing the status of the project. This project and other activities of the E-RSC are fully documented on the SPP website under its ICT & ITO heading.

06 RALSTON_Exhibit ABR-6.doc

Document 06 contains a list of transmission constraints that impacted unit commitment during the period April 2007 to June 2009. This information was provided as an exhibit in a recent rate case filing by Entergy Texas, Inc. with the Public Utility Commission of Texas.

Exhibit L

EPA Constrained Region Capacity Factors

Constrained Region	Unit	Unit Max Capacity	Unit Minimum Capacity	Average Monthly Capacity Factor	Local Stability Capacity Factor	Resource Deliverability Capacity Factor	Operational Flexibility Capacity Factor	On-Line Hours at Minimum	Total Natural Gas Usage
		(MW)	(MW)	(%)	(%)	(%)	(%)	(%)	mmBTU
Western	**Lewis Creek 1**	230	70	47%	24%	20%	2%	58%	4,301,923
Western	**Lewis Creek 2**	230	70	55%	24%	24%	7%	51%	4,968,032
WOTAB	**Sabine 1**	212	50	37%		17%	20%	37%	3,155,208
WOTAB	**Sabine 2**	212	50	30%		19%	11%	62%	2,598,981
WOTAB	**Sabine 3**	390	70	32%		16%	16%	54%	5,077,359
WOTAB	**Sabine 4**	525	185	45%	28%	15%	2%	47%	8,918,197
WOTAB	**Sabine 5**	470	55	15%	9%	4%	2%	78%	3,298,070
WOTAB	**Nelson 3**	130	25	16%		11%	5%	81%	1,067,708
WOTAB	**Nelson 4**	445	180	23%		20%	3%	66%	4,606,952
DSG	**Ninemile 3**	125	23	11%		8%	3%	84%	714,575
DSG	**Ninemile 4**	734	190	31%	19%	11%	1%	69%	9,528,484
DSG	**Ninemile 5**	740	210	34%	21%	12%	2%	61%	9,917,183
DSG	**Michoud 2**	235	40	30%		16%	14%	47%	2,697,734
DSG	**Michoud 3****	529	180	45%	23%	21%	1%	55%	7,546,917
Amite South	**Little Gypsy 1**	238	18	7%		6%	1%	98%	1,086,061
Amite South	**Little Gypsy 2**	410	24	3%		3%	1%	97%	1,010,463
Amite South	**Little Gypsy 3**	522	150	24%		21%	3%	82%	5,645,451
Amite South	**Waterford 1**	411	32	3%		3%		100%	1,221,822
Amite South	**Waterford 2**	411	32	7%		6%	1%	94%	1,601,183
MS	**Rex Brown 4**	209	24	4%	4%			69%	457,362
MS	**Gerald Andrus**	712	260	33%		24%	9%	58%	9,316,568
MS	**Baxter Wilson 1**	500	160	7%		5%	2%	65%	1,476,722
MS	**Baxter Wilson 2**	676	190	18%		13%	5%	71%	5,180,466
AR	**McClellan**	136	30	16%	16%			100%	1,018,797

**Michoud 3 average capacity factor reflects the June 2012 to September 2012 time period because of a May 2012 scheduled maintenance outage.

The Local Stability Capacity Factor represents the amount of energy produced by a generator during the ozone season to meet the local area need for voltage support and local stability.

The Resource Deliverability Capacity Factor represents the amount of energy produced by a generator during the ozone season to meet the local area need for energy to meet the local reserves in the event of an unplanned transmission or generator outage or that cannot be met by out-of-region resources due to transmission import limits.

The Operational Flexibility Capacity Factor represents the amount of energy produced by a generator during the ozone season to meet the System and Local area need for flexible load-following resources.

Source: 2012 Entergy Business Plan, Budget Forecast Case

Exhibit M

SPP Southwest Power Pool

May 11, 2010

E-RSC Study Scope Minimizing Bulk Power Costs

Objective

Objective of this study is to determine what (if any) transmission expansion, reconfiguration, and/or upgrades can reduce the production costs of Entergy related to operation of generating units (units) that Entergy operates as must-run. The study will distinguish between (1) units required to supply voltage support or prevent overloading of transmission lines (Reliability Must-Run or "RMR"), and/or (2) units that Entergy operates to provide "flexible capacity" (e.g., load-following, operating reserves). The Study should identify where a transmission project can cost effectively and reliably (1) replace a current unit's RMR function, and/or (2) result in production cost savings by providing transmission capacity that would permit lower heat rate generation to provide flexible capacity in place of those higher heat rate units currently providing Entergy's flexible capacity.

Study Process

The study process will make use of the information already provided by Entergy identifying the generation units to study. The following units will be included in the study. These units will be studied in the following priority order:

.

Plant	Capacity Factor 2008	2007	2006		weighted capacity factor
Lewis Creek	51.2	46.9	42.9		48.1
Ninemile Point	30.5	29.7	26.9		29.4
Sabine	25	28.3	28		26.6
Michoud	31.6	27.8	11.6	*	25.7
Roy S. Nelson (oil/gas)	22.7	18.8	14		19.6
Gerald Andrus	18.3	20.8	17.4		18.7
Little Gypsy	19.5	12.3	9.3		15.2
Baxter Wilson	17.2	16.2	8.6		14.8
Rex Brown	3.8	6.4	6.1		5.0
*capacity factor provided is summation of A.B. Paterson and Michoud					

The following study process will be applied to the above units. First, a powerflow analysis will be performed to determine what transmission upgrades would be required to entirely displace each generation unit used to provide for RMR requirements.

Steps:

1. Run powerflow analysis without the unit
2. Identify all reliability issues (voltage, stability, line loading)

3. Identify transmission upgrades to resolve the issues
4. Test powerflow analysis without the unit and with the identified transmission upgrade(s)

The above analysis will be performed using the 2013 and 2022 power flow models, developed for the CBA study, to ensure that the upgrades will work in the short-term as well as in the long-term horizons. This analysis will also take into consideration peak and off-peak conditions.

Then, run production cost simulations to determine if additional transmission upgrades would be required to partially or entirely displace each generation unit used to provide "flexible capacity".

Steps:

5. Run a production cost simulation without the unit
6. Identify all flexible capacity issues (load following, operating reserve requirements for spinning and non-spinning reserves)
7. Determine existing non-Entergy-owned generators that could provide flexible capacity at a lower cost
8. Identify transmission upgrades that could cost effectively permit other generation to replace existing high cost units providing flexible capacity
9. Rerun the production cost simulation without the unit and with the identified transmission upgrade

A production cost analysis incorporating all identified transmission upgrades necessary to displace a unit will be performed to validate the transmission solution and determine what congestion occurs when the unit is displaced. The production cost analysis will include constraints to represent needed capacity for regulation, load following, or operating reserves. The difference between production cost and adjusted production cost can be used as a gauge for the potential expenditure on transmission projects needed to address RMR and/or flexibility requirements. If necessary, a transmission solution will be identified to relieve congestion, and then that solution will be re-studied in the production cost model to determine if it is cost-effective. Both the powerflow and production cost processes will be iterative.

Additional benefits may be quantified based on several factors. If the unit is completely relieved of use, an analysis of the benefits for retiring the unit can be performed. Other benefits can also be enumerated, including loss reduction, reduction or elimination of fixed costs, carbon reduction, fuel price elasticity, market competitiveness, etc. Where possible, these, too, can be used in the determination of cost-effective transmission solutions.

Using the list of units ranking included above, the ERSC WG will develop a schedule to present the results to ERSC. Results will be provided for each generation unit and groupof units (e.g., located at a single site) as well as incrementally for the same as described below:

- Transmission solutions necessary to reduce operation of or replace the unit as an RMR
- Transmission solutions necessary to reduce operation of or replace the unit as a provider of flexible capacity
- Transmission solutions necessary to entirely displace generation unit
-
- Transmission solutions necessary to entirely displace generation group
-
- Transmission solutions necessary to displace all generation under study

The ability to perform both powerflow and production cost studies simultaneously will reduce study time by allow separate entities to perform these analyses. Based on the above scope of work, the estimated effort is […..] and expected study completion date is […..] . The study will be performed by […….].

The ERSC can use these results to evaluate whether it is cost effective to replace some or all of the existing units that provide RMR and/or flexible capacity with transmission expansion projects.

Exhibit N

Please see enclosed CD.

Exhibit O

Table. Transfer Limits between NEEM Regions (all limits in MW) - Transfer limits are unidirectional and should be stated as "FROM" column C "TO" columns D through R

		DESTINATION													
		AZ_NM_SNV	ENTERGY	ERCOT	FRCC	MAPP_CA	MAPP_US	MISO_IN	MISO_MI	MISO_MO_IL	MISO_W	MISO_WUMS	NE	NEISO	Non_RTO_Midwest
ORIGIN	AZ_NM_SNV														
	ENTERGY									2,260					
	ERCOT														
	FRCC														
	MAPP_CA						372				1,970				
	MAPP_US					165					2,635		2,000		
	MISO_IN								5,000	5,000					4,800
	MISO_MI							2,045				117			
	MISO_MO_IL		2,540					2,100			960				
	MISO_W					700	2,300			3,800		1,629	2,800		
	MISO_WUMS								99		1,137				
	NE						1,600				1,600				
	NEISO														
	Non_RTO_Midwest							4,450							
	NWPP						150								
	NYISO__A-F													600	
	NYISO_GHI													600	
	NYISO_J_&_K													0	
	IESO					262			1,840		140				
	PJM_Eastern_MAAC														
	PJM_Rest_of_MAAC														
	PJM_Rest_of_RTO							909	1,305	1,111	709	1,467			
	RMPA						200						310		
	SOCO		2,400		3,700										
	SPP_N		1,800							2,000	750		330		
	SPP_S	400	850	800											
	TVA		3,000							4,000					700
	VACAR														

Legend

Note: Non-existent links are blacked out.

		DESTINATION													
		NWPP	NYISO_A-F	NYISO_GHI	NYISO_J_&_K	IESO	PJM_Eastern_MAAC	PJM_Rest_of_MAAC	PJM_Rest_of_RTO	RMPA	SOCO	SPP_N	SPP_S	TVA	VACAR
ORIGIN	AZ_NM_SNV												400		
	ENTERGY										2,000	1,300	1,300	2,100	
	ERCOT												800		
	FRCC										900				
	MAPP_CA					330									
	MAPP_US	200								200					
	MISO_IN								992						
	MISO_MI					1,580			1,424						
	MISO_MO_IL								1,212			2,000		4,000	
	MISO_W					90			773			3,200			
	MISO_WUMS								1,600						
	NE									310		1,800			
	NEISO		600	600	430										
	Non_RTO_Midwest													2,400	
	NWPP														
	NYISO__A-F			4,250		1,600		1,000							
	NYISO_GHI		1,999		6,130		1,500								
	NYISO_J_&_K			1,999											
	IESO		1,725												
	PJM_Eastern_MAAC			500	330			8,000							
	PJM_Rest_of_MAAC		2,000				8,000		8,000						
	PJM_Rest_of_RTO							8,000						2,500	3,000
	RMPA											210			
	SOCO													2,600	2,000
	SPP_N									210			4,000		
	SPP_S											0			
	TVA								2,000		3,200				900
	VACAR								2,000		3,000			900	

Legend

Note: Non-existent links are blacked out.

Exhibit P

NEEM Transfer Limits Input Descriptions

FROM	TO	Description
ENTERGY	MISO_MO_IL	To obtain the MRM-NEEM Pipe Transfer Limit between MISO and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between MISO and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies.
ENTERGY	SOCO	To obtain the MRM-NEEM Pipe Transfer Limit between Southern Company and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between Southern Company and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
ENTERGY	SPP_N	To obtain the MRN-NEEM Pipe Transfer Limit between SPP and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then coordinated between SPP and Entergy.
ENTERGY	SPP_S	To obtain the MRN-NEEM Pipe Transfer Limit between SPP and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then coordinated between SPP and Entergy.
ENTERGY	TVA	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between TVA and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies.
MISO_MO_IL	ENTERGY	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
SOCO	ENTERGY	To obtain the MRM-NEEM Pipe Transfer Limit between Southern Company and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between Southern Company and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
SPP_N	ENTERGY	To obtain the MRN-NEEM Pipe Transfer Limit between SPP and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then coordinated between SPP and Entergy.
SPP_S	ENTERGY	To obtain the MRN-NEEM Pipe Transfer Limit between SPP and Entergy, a linear transfer analysis was performed in PSS(r) MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then coordinated between SPP and Entergy.
TVA	ENTERGY	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between TVA and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies.
AZ_NM_SNV	SPP_S	Ties with AZ_NM_SW were determined as the combined maximum capacity of the DC ties.
SPP_S	AZ_NM_SNV	Ties with AZ_NM_SW were determined as the combined maximum capacity of the DC ties.
SPP_S	ERCOT	Ties with ERCOT were determined as the combined maximum capacity of the DC ties.
SOCO	FRCC	The transfer capabilties provided as input in the MRN-NEEM model were obtained from the most recent FRCC - Southern joint TTC study. This interface is a voltage stability limited interface, and therefore, linear analysis on the baseline infrastructure case was not performed. Their are no transmission enhancements that are currently planned that would increase the transfer capability between these regions.
MAPP_CA	IESO	This is the current MH to IESO operating limit as reported by IESO.
MISO_MI	IESO	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_W	IESO	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
NYISO_A-F	IESO	Those numbers are coming from table 5.2 of the Ontario Transmission System document that is published along with the 18-Month Outlook Report. We also performed linear analysis (TLTG – generation to generation transfers) on BI case and the numbers (for some “pipes”) were very close to the ones from table 5.2.
IESO	MAPP_CA	For pipe values from "MAPP CA" to "OH" we used an operational guide from IESO.
MAPP_US	MAPP_CA	This is the current MAPP_US to MAPP_CA operating limit on this single element tie line as reported by MH.

MISO_W	MAPP_CA	The pipe values from "MAPP CA" to "MISO W" are documented in operational guide.
MAPP_CA	MAPP_US	This value is the current Saskatchewan to MAPP_US operating limit plus the current MH to US operating limit, reduced by the value reported for "MAPP_CA to MISO_W".
MISO_W	MAPP_US	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
NE	MAPP_US	The values for the pipe from "MAPP US" to "NE" are found using transfer study from generation to generation.
NWPP	MAPP_US	This is a DC tie to WECC. This value is the current operating limit for the DC tie.
RMPA	MAPP_US	This is a DC tie to WECC. This value is the current operating limit for the DC tie.
MISO_MI	MISO_IN	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_MO_IL	MISO_IN	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
Non_RTO_Midwest	MISO_IN	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
PJM_Rest_of_RTO	MISO_IN	PJM determined consensus limits with the external interface owners by examining several “data points” and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM’s internal interface capability with
IESO	MISO_MI	The number is coming from table 5.2 of the Ontario Transmission System document that is published along with the 18-Month Outlook Report. We also performed linear analysis (TLTG – generation to generation transfers) on BI case and the numbers (for some “pipes”) were very close to the ones from table 5.2.
MISO_IN	MISO_MI	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_WUMS	MISO_MI	Historical MISO_WUMS maximum import and export values as well as historical maximum import and export values for the individual "Pipes" connecting to the MISO_WUMS "Bubble" were gathered for the years 2008-2010. The MISO_WUMS maximum import and export values were then augmented by 70% of the rated normal capacity of the new tie facilities or upgraded tie facility ratings. The augmented MISO_WUMS maximum import and export values were then distributed over the "Pipes" connecting to the MISO_WUMS "Bubble" based on the historical maximum import and export values for the individual "Pipes" connecting to the MISO_WUMS "Bubble".
PJM_Rest_of_RTO	MISO_MI	PJM determined consensus limits with the external interface owners by examining several “data points” and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM’s internal interface capability with backbone upgrades and MISO Interface linear transfer analysis using the BI case.
MISO_IN	MISO_MO_IL	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_W	MISO_MO_IL	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
PJM_Rest_of_RTO	MISO_MO_IL	PJM determined consensus limits with the external interface owners by examining several “data points” and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM’s internal interface capability with backbone upgrades and MISO Interface linear transfer analysis using the BI case.

SPP_N	MISO_MO_IL	The transfer capacity was coordinated between SPP and MISO_MO_IL and were detemined by averaging the values obtained by the two entities.
TVA	MISO_MO_IL	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and MISO_MO_IL, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between TVA and MISO_MO_IL. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
IESO	MISO_W	The number is coming from table 5.2 of the Ontario Transmission System document that is published along with the 18-Month Outlook Report. We also performed linear analysis (TLTG – generation to generation transfers) on BI case and the numbers (for some “pipes”) were very close to the ones from table 5.2.
MAPP_CA	MISO_W	This is part of the MH to US stability limited interface. This value is the current operating limit, reduced by 200 MW, which is included in the value for "MAPP_CA to MAPP_US".
MAPP_US	MISO_W	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using PSS® MUST version 8.3.2.
MISO_MO_IL	MISO_W	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_WUMS	MISO_W	Historical MISO_WUMS maximum import and export values as well as historical maximum import and export values for the individual "Pipes" connecting to the MISO_WUMS "Bubble" were gathered for the years 2008-2010. The MISO_WUMS maximum import and export values were then augmented by 70% of the rated normal capacity of the new tie facilities or upgraded tie facility ratings. The augmented MISO_WUMS maximum import and export values were then distributed over the "Pipes" connecting to the MISO_WUMS "Bubble" based on the historical maximum import and export values for the individual "Pipes" connecting to the MISO_WUMS "Bubble".
NE	MISO_W	Values were coordinated between SPP and MISO_W and were detemined by averaging the values obtained by the two entities.
PJM_Rest_of_RTO	MISO_W	PJM determined consensus limits with the external interface owners by examining several “data points” and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM’s internal interface capability with backbone upgrades and MISO Interface linear transfer analysis using the BI case.
SPP_N	MISO_W	The transfer capacity was coordinated between SPP and MISO_W and were detemined by averaging the values obtained by the two entities.
MISO_MI	MISO_WUMS	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_W	MISO_WUMS	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
PJM_Rest_of_RTO	MISO_WUMS	PJM determined consensus limits with the external interface owners by examining several “data points” and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM’s internal interface capability with backbone upgrades and MISO Interface linear transfer analysis using the BI case.
MAPP_US	NE	The values for the pipe from "MAPP US" to "NE" are found using transfer study from generation to generation.
MISO_W	NE	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
RMPA	NE	This is a DC tie to WECC. This value is the current operating limit for the DC tie.
SPP_N	NE	The transfer capacity to NE was determined by using the first valid limiting FCITC transfer value under contingency.
NYISO_A-F	NEISO	The known 1200 MW New York-New England bi directional transfer limit (excluding the PAR controlled 1385 Norwalk-Northport cable at 200 MW and the Cross-Sound HVDC cable at 330 MW) was separated into the regions specified for NYISO in the NEEM bubble diagram. The 398 line (Pleasant Valley-Long Mountain) is the sole line connecting ISO-NE to the “NYISO GHI” region, while the rest of the lines between upstate New York and New England connect to the “NYISO A-F” region. (The 690 line, Salisbury-Smithfield, is open in the EIPC case, as usual, so that is not included in either interface.) Transfers between New York and New England were varied over a range of dispatch assumptions that resulted in an average split of 50/50 of the 1200 MW limit into the A-F and GHI regions resulting in the 600 MW ratings.

NYISO_GHI	NEISO	The known 1200 MW New York-New England bi directional transfer limit (excluding the PAR controlled 1385 Norwalk-Northport cable at 200 MW and the Cross-Sound HVDC cable at 330 MW) was separated into the regions specified for NYISO in the NEEM bubble diagram. The 398 line (Pleasant Valley-Long Mountain) is the sole line connecting ISO-NE to the "NYISO GHI" region, while the rest of the lines between upstate New York and New England connect to the "NYISO A-F" region. (The 690 line, Salisbury-Smithfield, is open in the EIPC case, as usual, so that is not included in either interface.) Transfers between New York and New England were varied over a range of dispatch assumptions that resulted in an average split of 50/50 of the 1200 MW limit into the A-F and GHI regions resulting in the 600 MW ratings.
NYISO_J_&_K	NEISO	The known 1200 MW New York-New England bi directional transfer limit (excluding the PAR controlled 1385 Norwalk-Northport cable at 200 MW and the Cross-Sound HVDC cable at 330 MW) was separated into the regions specified for NYISO in the NEEM bubble diagram. The 398 line (Pleasant Valley-Long Mountain) is the sole line connecting ISO-NE to the "NYISO GHI" region, while the rest of the lines between upstate New York and New England connect to the "NYISO A-F" region. (The 690 line, Salisbury-Smithfield, is open in the EIPC case, as usual, so that is not included in either interface.) Transfers between New York and New England were varied over a range of dispatch assumptions that resulted in an average split of 50/50 of the 1200 MW limit into the A-F and GHI regions resulting in the 600 MW ratings.
MISO_IN	Non_RTO_Midwest	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
TVA	Non_RTO_Midwest	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and Non_RTO_Midwest, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between TVA and Non_RTO_Midwest. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
MAPP_US	NWPP	This is a DC tie to WECC. This value is the current operating limit for the DC tie.
IESO	NYISO_A-F	Those numbers are coming from table 5.2 of the Ontario Transmission System document that is published along with the 18-Month Outlook Report. We also performed linear analysis (TLTG – generation to generation transfers) on BI case and the numbers (for some "pipes") were very close to the ones from table 5.2.
NEISO	NYISO_A-F	The known 1200 MW New York-New England bi directional transfer limit (excluding the PAR controlled 1385 Norwalk-Northport cable at 200 MW and the Cross-Sound HVDC cable at 330 MW) was separated into the regions specified for NYISO in the NEEM bubble diagram. The 398 line (Pleasant Valley-Long Mountain) is the sole line connecting ISO-NE to the "NYISO GHI" region, while the rest of the lines between upstate New York and New England connect to the "NYISO A-F" region. (The 690 line, Salisbury-Smithfield, is open in the EIPC case, as usual, so that is not included in either interface.) Transfers between New York and New England were varied over a range of dispatch assumptions that resulted in an average split of 50/50 of the 1200 MW limit into the A-F and GHI regions resulting in the 600 MW ratings.
NYISO_GHI	NYISO_A-F	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a "pipe and bubble" model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis.
PJM_Rest_of_MAAC	NYISO_A-F	PJM determined consensus limits with the external interface owners by examining several "data points" and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM's internal interface capability with backbone upgrades
NEISO	NYISO_GHI	The known 1200 MW New York-New England transfer limit (excluding the PAR controlled 1385 Norwalk-Northport cable at 200 MW and the Cross-Sound HVDC cable at 330 MW) was separated into the regions specified for NYISO in the NEEM bubble diagram. The 398 line (Pleasant Valley-Long Mountain) is the sole line connecting ISO-NE to the "NYISO GHI" region, while the rest of the lines between upstate New York and New England connect to the "NYISO A-F" region. (The 690 line, Salisbury-Smithfield, is open in the EIPC case, as usual, so that is not included in either interface.) Transfers between New York and New England were varied over a range of dispatch assumptions that resulted in an average split of 50/50 of the 1200 MW limit into the A-F and GHI regions resulting in the 600 MW ratings.
NYISO_A-F	NYISO_GHI	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a "pipe and bubble" model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis.

NYISO_J_&_K	NYISO_GHI	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a “pipe and bubble” model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis. This pipe represents the merging of two pipes from the standard NYISO "pipe" model.
PJM_Eastern_MAAC	NYISO_GHI	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a “pipe and bubble” model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis. This pipe represents the merging of two"bubbles" from the standard NYISO model that represent controllable ties and assumptions of the NEEM model.
NEISO	NYISO_J_&_K	The known 1200 MW New York-New England bi directional transfer limit (excluding the PAR controlled 1385 Norwalk-Northport cable at 200 MW and the Cross-Sound HVDC cable at 330 MW) was separated into the regions specified for NYISO in the NEEM bubble diagram. The 398 line (Pleasant Valley-Long Mountain) is the sole line connecting ISO-NE to the “NYISO GHI” region, while the rest of the lines between upstate New York and New England connect to the “NYISO A-F” region. (The 690 line, Salisbury-Smithfield, is open in the EIPC case, as usual, so that is not included in either interface.) Transfers between New York and New England were varied over a range of dispatch assumptions that resulted in an average split of 50/50 of the 1200 MW limit into the A-F and GHI regions resulting in the 600 MW ratings.
NYISO_GHI	NYISO_J_&_K	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a “pipe and bubble” model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis. This pipe represents the merging of two pipes from the standard NYISO "pipe" model.
PJM_Eastern_MAAC	NYISO_J_&_K	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a “pipe and bubble” model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis. This pipe represents the merging of two"bubbles" from the standard NYISO model that represent controllable ties and assumptions of the NEEM model.
NYISO_GHI	PJM_Eastern_MAAC	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a “pipe and bubble” model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis. This pipe represents the merging of two"bubbles" from the standard NYISO model to account for the RECO load included in the PJM_Eastern_MAAC bubble
PJM_Rest_of_MAAC	PJM_Eastern_MAAC	PJM determined consensus limits with the external interface owners by examining several “data points” and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM’s internal interface capability with backbone upgrades
NYISO_A-F	PJM_Rest_of_MAAC	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a “pipe and bubble” model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis.
PJM_Eastern_MAAC	PJM_Rest_of_MAAC	PJM determined consensus limits with the external interface owners by examining several “data points” and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM’s internal interface capability with backbone upgrades
PJM_Rest_of_RTO	PJM_Rest_of_MAAC	PJM determined consensus limits with the external interface owners by examining several “data points” and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM’s internal interface capability with backbone upgrades.

MISO_IN	PJM_Rest_of_RTO	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_MI	PJM_Rest_of_RTO	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_MO_IL	PJM_Rest_of_RTO	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_W	PJM_Rest_of_RTO	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_WUMS	PJM_Rest_of_RTO	Historical MISO_WUMS maximum import and export values as well as historical maximum import and export values for the individual "Pipes" connecting to the MISO_WUMS "Bubble" were gathered for the years 2008-2010. The MISO_WUMS maximum import and export values were then augmented by 70% of the rated normal capacity of the new tie facilities or upgraded tie facility ratings. The augmented MISO_WUMS maximum import and export values were then distributed over the "Pipes" connecting to the MISO_WUMS "Bubble" based on the historical maximum import and export values for the individual "Pipes" connecting to the MISO_WUMS "Bubble".
PJM_Rest_of_MAAC	PJM_Rest_of_RTO	PJM determined consensus limits with the external interface owners by examining several “data points” and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM’s internal interface capability with backbone upgrades
TVA	PJM_Rest_of_RTO	To obtain the MRM-NEEM Pipe Transfer Limit between PJM and TVA, OASIS data, operating history, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case, and the existing CRA NEEMS data were reviewed. The data was evaluated and coordinated pipe sizes were determined by PJM and TVA.
VACAR	PJM_Rest_of_RTO	To obtain the MRM-NEEM Pipe Transfer Limit between PJM and VACAR, OASIS data, operating history, and the existing CRA NEEMS data were reviewed; as well as a linear transfer analysis performed with PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The data and analysis results were evaluated and coordinated pipe sizes jointly determined by PJM and VACAR. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning economic and reliability studies.
MAPP_US	RMPA	This is a DC tie to WECC. This value is the current operating limit for the DC tie.
NE	RMPA	This is a DC tie to WECC. This value is the current operating limit for the DC tie.
SPP_N	RMPA	Ties with RMPA were determined as the combined maximum capacity of the DC ties.
FRCC	SOCO	The transfer capabilties provided as input in the MRN-NEEM model were obtained from the most recent FRCC - Southern joint TTC study. This interface is a voltage stability limited interface, and therefore, linear analysis on the baseline infrastructure case was not performed. Their are no transmission enhancements that are currently planned that would increase the transfer capability between these regions.
TVA	SOCO	To obtain the MRM-NEEM Pipe Transfer Limit between Southern Company and TVA, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between Southern Company and TVA. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
VACAR	SOCO	To obtain the MRM-NEEM Pipe Transfer Limit between Southern Company and VACAR, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between Southern Company and VACAR. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
MISO_MO_IL	SPP_N	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.

MISO_W	SPP_N	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
NE	SPP_N	The transfer capacity to SPP_N was determined by using the first valid limiting FCITC transfer value under contingency.
RMPA	SPP_N	Ties with RMPA were determined as the combined maximum capacity of the DC ties.
SPP_S	SPP_N	The transfer capacity to SPP_N was determined as the first valid limiting FCITC transfer value under contingency.
ERCOT	SPP_S	Ties with ERCOT were determined as the combined maximum capacity of the DC ties.
SPP_N	SPP_S	The transfer capacity to SPP_S was determined by using the first valid limiting FCITC transfer value under contingency.
MISO_MO_IL	TVA	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and MISO_MO_IL, a linear transfer analysis was performed in PSS(r) MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between TVA and MISO_MO_IL. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
Non_RTO_Midwest	TVA	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and Non_RTO_Midwest, a linear transfer analysis was performed in PSS(r) MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between TVA and Non_RTO_Midwest. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
PJM_Rest_of_RTO	TVA	To obtain the MRM-NEEM Pipe Transfer Limit between PJM and TVA, OASIS data, operating history, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case, and the existing CRA NEEMS data were reviewed. The data was evaluated and coordinated pipe sizes were determined by PJM and TVA.
SOCO	TVA	To obtain the MRM-NEEM Pipe Transfer Limit between Southern Company and TVA, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between Southern Company and TVA. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
VACAR	TVA	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and VACAR, the tie line capacity (contract path) between the regions and the results of linear transfer analysis performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case were reviewed. There were no limiting facilities identified at transfer levels below the contract path capacity of the tie lines between the regions. FERC tariff regulations limit the transfer capability to the lower of ATC or contract path capacity.
PJM_Rest_of_RTO	VACAR	To obtain the MRM-NEEM Pipe Transfer Limit between PJM and VACAR, OASIS data, operating history, and the existing CRA NEEMS data were reviewed; as well as a linear transfer analysis performed with PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The data and analysis results were evaluated and coordinated pipe sizes jointly determined by PJM and VACAR. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning economic and reliability studies.
SOCO	VACAR	To obtain the MRM-NEEM Pipe Transfer Limit between Southern Company and VACAR, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between Southern Company and VACAR. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
TVA	VACAR	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and VACAR, the tie line capacity (contract path) between the regions and the results of linear transfer analysis performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case were reviewed. There were no limiting facilities identified at transfer levels below the contract path capacity of the tie lines between the regions. FERC tariff regulations limit the transfer capability to the lower of ATC or contract path capacity.

Exhibit Q

Entergy Regional State Committee (ERSC) Minimizing Bulk Power Cost Study (MBPC)

August 24, 2011

New Orleans, LA

Antoine Lucas
alucas@spp.org
501.614.3382

SPP Southwest Power Pool

Overview

- MBPC Study Methodology
- MBPC Study Status
- MBPC Next Steps
- MBPC Project Schedule
- MBPC Project Budget

MBPC Study Methodology

- Develop transmission power flow and production cost model for years 2013 and 2022.
- Conduct economic and peak hour transmission analysis on the base case for each study region for 2013.
- Develop change case transmission solutions to resolve steady state thermal and voltage issues observed in each study region for the 2013 base case.
- Conduct economic and peak hour transmission analysis on the change case for each study region for 2013.
- Conduct economic and peak hour transmission analysis on the base case for each study region for 2022.

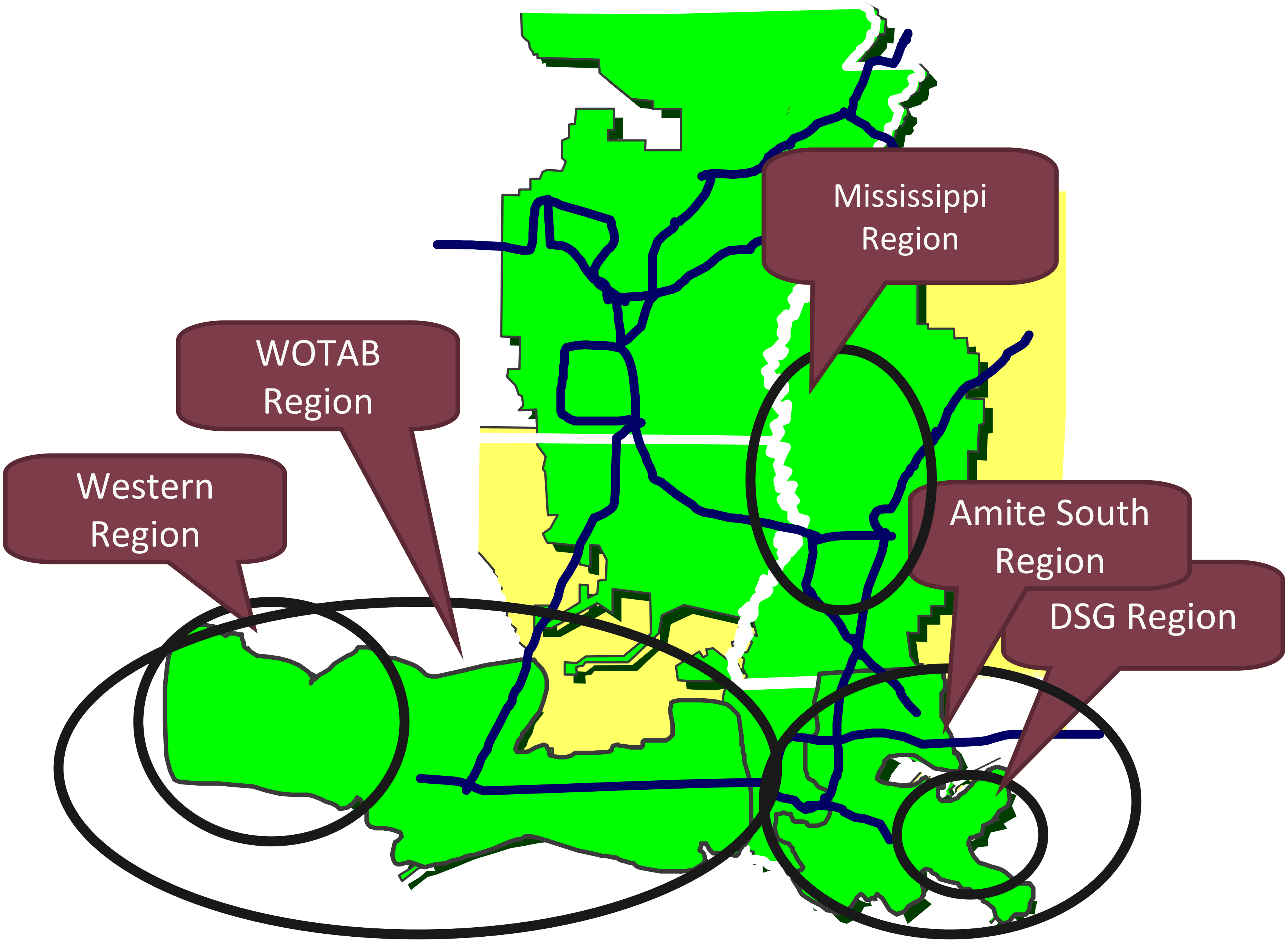
MBPC Study Methodology (continued)

- Using the 2013 transmission solutions as a baseline, develop change case transmission solutions to resolve steady state thermal and voltage issues observed in each study region for the 2022 base case.
- Conduct economic and peak hour transmission analysis on the change case for each study region for 2022.
- Select final single transmission solution set for each study region that resolves steady state thermal and voltage issues observed in both the 2013 and 2022 model years.

MBPC Study Methodology (continued)

- **Conduct economic analysis on both the 2013 and 2022 models to calculate the estimated annual production cost benefits of the final transmission solution set for each study region.** ***(Interpolate benefits for interim years)***
- **Calculate the estimated annualized capital cost of the final transmission solution set for each study region.**
- **Calculate the estimated cost/benefit ratio for each study region.**

Study Areas



Mississippi Region
WOTAB Region
Western Region
Amite South Region
DSG Region

MBPC Study Status

- 2013 Economic and Powerflow Reference Case Development - Complete
- 2013 Western Region Analysis – Complete
- 2013 WOTAB Region Analysis – Complete
- 2013 DSG Region Analysis – Complete
- 2013 Amite South Region Analysis – Complete
- 2013 Mississippi Region Analysis – Underway
- 2022 Economic and Powerflow Reference Case Development – Complete
- 2022 WOTAB Region Analysis – Underway

MBPC Next Steps

- Complete 2013 Mississippi Region Analysis.
- Complete 2022 WOTAB Region Analysis.
- Begin 2022 Western, DSG, Amite South, and Mississippi Region analysis.
- Stakeholder Meetings
- Capture Metrics
- Run Sensitivity Analysis
- Develop Final Report

MBPC Schedule

- All study region analysis remains on schedule to be completed by December 9, 2011
- All sensitivity analysis remains on schedule to be completed by February 17, 2012
- Final Report is scheduled to be completed by February 29, 2012.
- A meeting will be scheduled for a presentation of the final results.

MBPC Project Budget

- **Project is forecasted to be completed approximately 14% over budget.** ***(Primarily unbudgeted database development costs)***
- **Costs would be trimmed significantly by eliminating Baxter Wilson and Andrus units from the MBPC study.**
- **This change in scope reduces the forecasted budget overage to approximately 3%.**
- **This 3% budget overage could be eliminated by reducing post-study sensitivity analysis by around 50% or by increasing the project budget by 3%.**
- **ABB travel budget would also need to be increased to facilitate future in-person stakeholder meetings.**

Antoine Lucas: 501-614-3382, alucas@spp.org

QUESTIONS?

Exhibit R

KEAN | MILLER LLP
ATTORNEYS AT LAW

MAUREEN N. HARBOURT, PARTNER
225.382.3412, FAX: 225.388.9133
MAUREEN.HARBOURT@KEANMILLER.COM

August 19, 2011

Ms. Terri Lemoine
Records and Recording
Louisiana Public Service Commission
Galvez Building
602 North Fifth Street, 12th Floor
Baton Rouge, Louisiana 70802

VIA HAND DELIVERY

RE: Lafayette Utilities System
DOCKET NO. R-29380
SUBDOCKET B
Our File No. 17905-9

Dear Terri:

After submitting comments on behalf of the Lafayette Utilities System in this docket on August 17, 2011, we realized that there were errors with the data provided for the TJ Labbe' station on the table included on page 4 of the comments (although the correct information for this unit was included on Exhibit 1 to the comments). In addition, there was a minor error on page 4 of Exhibit 1. We have corrected these errors and request that the attached corrected version be reflected on the LPSC docket. We have also sent a service copy of the revised comments to those on the service list.

If you have any questions, please do not hesitate to contact us.

Sincerely,

Maureen N. Harbourt

Maureen N. Harbourt

MNH/tjh
Enclosure
cc: Official Service List

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BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

LOUISIANA PUBLIC SERVICE COMMISSION, EX PARTE.	DOCKET NO. R-29380 SUBDOCKET B

IN RE: AN INVESTIGATION INTO THE RATEMAKING AND GENERATION PLANNING IMPLICATIONS OF THE U.S. EPA CLEAN AIR INTERSTATE RULE.

REVISED COMMENTS OF LAFAYETTE UTILITIES SYSTEM ON EPA CROSS-STATE AIR POLLUTION RULE

On behalf of our client, the Lafayette Utilities System ("LUS"), we are submitting revised comments to the Louisiana Public Service Commission ("LPSC") with regard to the LPSC Notice of Technical Conference and Request for Comments in this docket. The revision corrects minor errors on page 4 and on Exhibit 1, p.4, of the original comments filed by LUS on August 17, 2011. The revised and original comments are the same in all other respects. LUS is a department within the Lafayette Consolidated Government serving more than 65,000 retail customers in the City of Lafayette and certain areas of the Parish of Lafayette, Louisiana.

The LUS Power Production Division is responsible for the operation and maintenance of the Louis "Doc" Bonin gas-fired steam turbine generation facility (3 units for a total of 295MW) and the T.J. Labbe' and Hargis-Hebert gas-fired combustion turbine generation facilities (each plant consists of two 50-MW combustion turbines generators). Through the Lafayette Public Power Authority ("LPPA"), LUS also owns a 50% share of the Rodemacher II coal-fired power generation plant (261.5 MW share of a 523 MW nameplate rating), located at the Brame Energy Center in central Louisiana. The Rodemacher II unit is also partially owned by CLECO Power

LLC ("CLECO") (30% share) and by the Louisiana Energy and Power Authority ("LEPA") (20% share). It is located within the CLECO transmission system.

LUS serves firm load with a peak demand of over 470 MW. LUS owns, or has allocated to it in its own name, 740 MW of generating resources, including its share of Rodemacher II and an 18 MW allocation of hydroelectric capacity from the Southwestern Power Administration. LUS purchases and sells economy energy, and is also a seller or potential seller of generation to others in its vicinity. LUS is a member of LEPA.

The circumstances of this sub-docket have changed since the docket was originally opened, as the U.S. Environmental Protection Agency ("EPA") has recently promulgated its final Cross-State Air Pollution Rule ("CSAPR")[1] that replaces the former Clean Air Interstate Rule ("CAIR").[2] As a result, on August 2, 2011, LPSC Staff issued a Notice of Technical Conference and Request for Comments.

LUS has serious concerns with the final CSAPR and appreciates the interest of the LPSC concerning the impact of electric service reliability if CSAPR is implemented as enacted by EPA. Among LUS's concerns are: whether Louisiana should be included in the CSAPR at all; if Louisiana is included, that the budget allocated for Louisiana Electric Generating Units ("EGUs") is inadequate and is much smaller than necessary to satisfy the Clean Air Act "good neighbor" provisions that are the sole legal basis for the rule; the unexpected change in the number of allowances provided to LUS units resulting in inadequate allowances that will result in curtailment of operations in the near term and

[1] 76 Fed. Reg. 48208, August 8, 2011.

[2] In *State of North Carolina v. EPA*, 531 F.3d 1176 (D.C. Cir. 2008), the court invalidated the CAIR, principally because it allowed interstate trading among the entire body of states in the Eastern half of the United States, and thus did not assure that required reductions would achieve the purposes of 42 U.S.C. 7410(a)(2)(D) of the Clean Air Act, which is to require each state to assure that emissions from its state do not significantly contribute to nonattainment by another state with a National Ambient Air Quality Standard and do not interfere with maintenance of such standards in another state. The court also indicated that the "significant contribution" and "interference with maintenance" are separate determinations that must be made by EPA and the states.

excessive costs in the longer term; and the compliance date which leaves wholly inadequate time within which to reduce emissions to meet the allowances provided.

The following represents LUS's responses to the specific LPSC information requests:

1) If you are an LPSC-jurisdictional utility, please provide your assessment of the following:

LUS is not a jurisdictional entity. However, LUS is providing the following information to the LPSC as such is relevant to the inability of other jurisdictional entities to obtain allowances from LUS (as none will be available), and is relevant to the LPSC understanding of the state-wide impact of CSAPR.

a. Whether the utility has been allocated sufficient allowances under CSAPR to meet its jurisdictional retail load.

LUS was not allocated sufficient allowances for ozone season NOx under CSAPR. Under the initial *proposed* rule (then called the Clean Air Transport Rule or CATR), LUS was to have been allocated approximately 2094 allowances. This would have constituted sufficient allowances to meet compliance without expensive retrofits of equipment or curtailing of operations. As LUS's only available source of information was the proposed rule, such was relied upon in developing its planning. Unfortunately, LUS received 72% less credits in the final CSAPR than were originally proposed in the CATR. This shortfall has left LUS in an untenable position.

Under the final CSAPR rule, LUS will be allocated only 588 credits (which includes half of the credits allocated to Rodemacher Unit II, of which the City of Lafayette owns 50%). During the 2010 Ozone Season, LUS emitted 802 tons of NOx. The financial effect of the CSAPR rule is that LUS has gone from a position of significant excess allowances to a shortfall. The devastating effect is that the new rule allows LUS only seven months to manage this catastrophe.

b. Whether the allocations provided to each generating unit are correct and if not, please specifically state the erroneous allocations.

LUS believes that the central problem is that Louisiana should not be included in CSAPR at all because the evidence does not support that Louisiana emissions significantly contribute to ozone nonattainment in Texas nor interfere with maintenance of the ozone standard in Texas as projected by EPA. That said, even if Louisiana is included in the CSAPR, the budget for ozone season NOx emissions provided to Louisiana as a whole was too small. The budget proposed initially for Louisiana under the CATR proposal was 21,220 tons per year. EPA modeling, using the IPM v. 3.02, together with the CAMX air quality model projected that limiting Louisiana EGUs to this amount would result in eliminating the then projected impact of all Louisiana ozone season NOx emissions on both the Houston/Galveston/Brazoria area and Dallas/Ft. Worth areas of Texas. However, LUS and other commenters pointed out that EPA had included over

150,000 tons more NOx and some excessive VOC emissions in its estimates for the model. EPA did lower the amount of NOx estimated from Louisiana sources (mobile sources, nonroad sources, area sources, non-EGU point sources and EGU point sources) somewhat during the modeling for the final CSAPR as a result of these comments. As a result, EPA projected that Louisiana would no longer have any impact on the Dallas-Ft. Worth area, but would still have an impact on ozone in the HGB Area. However, rather than increasing the ozone season NOx budget as would be expected from these findings, EPA *lowered* the Louisiana ozone season NOx budget in the final rule to only 13,400 tons per year – a decrease of over 8,000 tons even though the impact was projected to be even smaller than the impact at 21,220 tons. This simply does not make sense. And, to add insult to injury, EPA reserved 3% of that budget for new sources (those commencing commercial operation after January 1, 2010), allocating only 97% to existing sources. As will be discussed below, LUS believes that the IPM model provides inaccurate estimates and should not be used for establishing the state budget.

Specifically, the proposed and final allocations to the units in which LUS has an interest, compared to actual NOx emissions over the 2005-2010 period are provided below:

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012	Shortage Compared to 2009/2010 post CAIR average	Shortage Compared to Maximum Yr since 2005
TJ Labbe' 56108		0	0	40	(+15)	-0.7
2010	40.7					
2009	7.9					
2008	34.1					
2007	24.1					
2006	28.9					
2005	3.8					
Doc Bonin 1443		328	268	128	-71	-359
2010	234.9					
2009	162.7					
2008	68.6					
2007	24.2					
2006	48.9					
2005	486.6					
Hargis-Hebert Electric 56283		8	1	38	-7	-0.6
2010	38.6					

2009	23.5					
2008	32.0					
2007	30.2					
2006	23.0					
Facility Name - Facility ID (ORISPL)	**Actual Ozone Season NO_x**	**Original Proposed Transport Rule Allocations**	**Revised NODA Summer NOx Allocation (IPM v. 4.10)**	**CSAPR NOx Ozone Season Allocation 2012 [ii]**	**Shortage Compared to 2009/201/ post CAIR average**	**Shortage Compared to Maximum Yr since 2005**
Brame Energy Center (f/k/a/ Rodemacher) 6190 [Unit 2 only]		3505		764	-410	-2960
2010	1133.9					
2009	1214.2					
2008	2669.2					
2007	2747.4					
2006	3723.7					
2005	3048.9					

c. Whether any EPA estimates of limited or shut down generation plants are reasonable and consistent with current generation planning.

EPA did not indicate in any of its technical background documents that LUS would be required to shut down or retrofit any the units it directly operates or in which LUS has an interest. In fact, the EPA documents specifically indicate that such would NOT be required. However, the IPM v. 4.10 base case and remedy case modeling performed by EPA simply projected that the LUS units would only be operating at the rates indicated in paragraph I.b., above. This projection is obviously based on erroneous information. The actual operating rates and NOx emissions over the past six years, as indicated above, are the best forecast of what rates and emissions these units will have in 2012.

d. Please identify each unit that has erroneous operating assumptions/forecast under the EPA's dispatch modeling and identify the appropriate model.

LUS is not certain what is meant by EPA's dispatch model or identifying the appropriate model, and is therefore not responding to this question at this time. LUS will address issues with EPA's use of the IPM in its rulemaking under its response to question 11, below.

e. Please identify all generating units slated to be placed into extended shut-down, retirement or repowering.

LUS has had insufficient time to determine whether any of its generating units will be placed into extended shut-down, retirement or repowering as a result of CSAPR.

2) Based on the above assessments, how does the utility intend to meet the new ozone season emission requirements included in the SCAPR?

LUS does not believe there are sufficient allowances available for purchase within Louisiana as the Louisiana budget is so low compared to actual operating conditions of Louisiana EGUs. See Table attached as Exhibit 1.

LUS believes that if CSAPR is enforced, it will be required to curtail operations substantially during at least he 2012 -2014 ozone seasons. LUS has an estimate from Sargent & Lundy for installation of an SCR on the Rodemacher II unit. The consultant estimates 40 months for design, permitting, construction and shakedown of this system. Further, because LUS is a municipality, it would be required to issue bonds for a project of this size. LUS estimates that the bond process would take 6 to 8 months to complete – thus it is more likely that curtailment would have to occur until after the 2015 ozone season.

The cost of an SCR is projected to be $130,000,000.00. There could also be additional operating costs, projected to be about $1,600,000.00 per year. The additional costs would cause the utility bill of the average residential customer to rise by $120 annually.

3) Please provide a detailed explanation including any unit closures, interruptions, or curtailments.

LUS has had insufficient time to make this determination.

4) Please provide any preliminary estimates that estimate the increased capital investments and annual operating costs associated with complying with the proposed CSAPR.

See response to question 2, above.

5) Please provide any analyses or generally explain how system re-dispatch may be used to meet the new CSAPR requirements. If system dispatch is inadequate to meet the CSAPR, please explain the extent to which (in total emissions and/or percentage terms) redispatch may be used to meet a portion of the CSAPR requirements.

LUS has had insufficient time to make this determination

6) Please explain the degree to which demand-side resources such as energy efficiency and load management programs can be used as a resource to meet the CSAPR requirements.

LUS has had insufficient time to make this determination.

7) Please provide, or generally discuss, the reliability implications associated with meeting CSAPR, particularly in the near term (summer 2012).

LUS has had insufficient time to make this determination. It should be noted that the North American Electric Reliability Corporation (NERC) and the Southwest Power Pool (SPP) are still in the process of evaluating the impacts of the CSAPR. The NERC sent a letter to all the Regions requesting an update for information for the 2011 Long-Term Reliability Assessment. As a result of this letter, SPP has sent LUS a letter requesting LUS provide information regarding how the CSAPR will affect LUS operations. This letter is to be submitted August 23, 2011. LUS is in the process of investigation and formulation of a response. The SPP did previously send a letter to EPA stating SPP's reliability concerns regarding several of EPA's other proposed rules. (See Exhibit 2 attached.)

8) Please identify and explain any special load interruption procedures that may be required in the event of a reliability challenge associated with meeting CSAPR requirements.

LUS has had insufficient time to make this determination.

9) Please provide all employment impacts that may arise as a result of CSAPR.

LUS has not had sufficient time to analyze the employment impacts that may arise as a result of CSAPR. As a general matter, if LUS is required to restrict electrical power to its customers within the Lafayette area over the next several years until LUS is able to plan and implement NOx controls sufficient to maintain needed electricity for local demand, LUS expects that some businesses will be impacted by having to curtail their own operations (due to lack of insufficient power for operations and/or lack of ability to cool personnel and equipment) and may, therefore, reduce the number of employees or the hours of work for employees with commensurate pay loss. LUS would intend to work with hospitals and medical clinics, the University of Louisiana – Lafayette, and major electrical energy users to plan ahead for power curtailments to the maximum extent possible.

10) Does your organization intend to file a request for reconsideration or petition for judicial review on the EPA's final CSAPR? Please explain.

Yes, LUS intends to request EPA to formally reconsider the rulemaking and to stay the rule while such reconsideration is ongoing. At this time, LUS has not determined whether it will file a petition for judicial review of the rule, but LUS believes that it is likely that it will file such a petition pursuant to Section 307 of the Clean Air Act.

11) What is your position on whether the LPSC should file a request for reconsideration or petition for judicial review? In so doing please provide detailed support for your position.

a. **What issues should the LPSC consider in its decision to pursue a legal remedy?**

b. **What relief should be requested by the LPSC for its jurisdictional utilities and their ratepayers?**

Yes, the LPSC should pursue reconsideration and/or judicial review to urge that CSAPR should not be applied to Louisiana, to challenge the budget allocated to Louisiana, and to suspend implementation of CSAPR until such time that adequate time is allowed to develop alternative solutions to meet electric reliability needs in a reasonable and cost-effective manner consistent with the "good neighbor" obligation not to contribute to nonattainment problems in the Houston area. LPSC owes a duty of protection to the electrical consumers of Louisiana to take legal action to prevent the devastating consequences to Louisiana that will result if CSAPR is allowed to become effective for the 2012 ozone season.

In both the petition for reconsideration and the petition for judicial review LUS urges LSPC to raise the following issues:

Louisiana Should Not Be Included in the CSAPR Because Louisiana Emissions Do Not Impact the Houston Area As Projected by EPA

LPSC should request that Louisiana not be subject to the rule for ozone season NOx reductions because the Clean Air Act authorizes the rule only if interstate transport of Louisiana emissions are "significantly impacting" the ability of another state to comply with the 1997 National Ambient Air Quality Standard for ozone ("1997 Ozone NAAQS") or are interfering with the ability of another state to "maintain attainment." EPA included Louisiana in the rule only because its ***modeled projections predict*** that in 2012 Louisiana emissions will be significantly impacting the ability of the Houston/Galveston/Brazoria area (the "HGB Area") to meet the ozone standard at 3 monitors in the HGB Area and will cause interference with maintenance of the standard at 2 other monitors within the area.

EPA's predictions deviate substantially from actual facts and should be rejected. In fact, all 5 of the monitors were in compliance with the standard at the end of the 2010 ozone season, the most recent season for which certified data is available.[3] Of these, most have been in compliance with the ozone standard for more than 4 years. There is no rational basis to project that Louisiana emissions are impacting or will impact the HGB Area in 2012 or beyond. EPA's own projections from numerous rulemakings predict that ozone season NOx emissions will decline even without the CSAPR. Further, all parishes in Louisiana are in compliance with the 1997 Ozone NAAQS and the Beaumont/Port Arthur Area which lies between Louisiana and the HGB Area are in compliance and have been for at least two years. Real facts must trump modeled projections. EPA's projections do not jibe with real data primarily because EPA has included too much NOx emissions in its projections. EPA's estimate of NOx emissions is more than 125,000 tons of NOx greater than the certified NOx emissions inventories that was certified by the Louisiana Department of Environmental Quality using EPA methods and which has been accepted in the past by EPA Region 6. While the LPSC staff and other commenters commented on these issues using 2005-2009 data, 2010 data which further supports the LPSC staff positions was not available at the time of the comment period on the proposed CSAPR; thus, such new data is grounds for reconsideration of this issue.

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[3] Uncertified preliminary data from 1 monitor in Brazoria indicate that the design value for such monitor is 1 part per billion over the 1997 Ozone NAAQS. However, it is unknown at this time whether this monitor has been affected by an exceptional event that would not be used in determining compliance.

During the rulemaking, the LPSC staff submitted comments to EPA adopting by reference the comments of the Louisiana Chemical Association to the effect that Louisiana should not be included in the rule for ozone season NOx reductions because Louisiana emissions do not significantly impact the ability of the HGB Area to meet the 1997 primary ozone standard, nor do Louisiana emissions interfere with the ability of the HGB area to maintain that standard. Thus, LPSC has the ability to raise this issue on judicial review. The entire legal basis for the imposition of NOx reduction requirements on Louisiana sources is EPA's projected modeling that determined that Louisiana emissions of NOx and VOCs "significantly impact" the ability of three monitors in the HGB Area to attain the 1997 Ozone NAAQS and "interfere with maintenance" of that standard at two additional monitors.

LUS believes that EPA's projection is based on a faulty methodology, inaccurate emissions inventories, and inaccurate modeling. The HGB Area achieved attainment with the 1997 Ozone NAAQS in 2009 and remained in attainment in 2010. There are 21 monitors within the HGB Area. EPA projected that Louisiana emissions affect 5 monitors out of those 21. Four of the 5 monitors allegedly impacted by Louisiana emissions have had design values below the ozone standard for at least 3 years. Three of these 4 have current design values more than 10 ppb below the standard, and are clearly unaffected in their ability to maintain the standard by Louisiana emissions. The fifth monitor was in compliance with the standard during 2009 and 2010; but preliminary uncertified data indicate that it now may have a design value just 1 part per billion over the standard. However, there is a great deal of circumstantial evidence to indicate that this particular monitor, the Manvel Croix monitor in Brazoria County, is not impacted by Louisiana.

First, all other monitors in the HGB area are in compliance. That Louisiana emissions would impact one monitor, but not the others, is highly unlikely. Second, all Louisiana parishes are in compliance with the 1997 Ozone NAAQS. It is highly unlikely that Louisiana would cause nonattainment in another state when all parishes in Louisiana are in attainment. Third, the Beaumont/Port Arthur Area is in attainment of the 1997 Ozone NAAQS.[4] It is highly unlikely that Louisiana is causing nonattainment problems in HGB when it is not causing such problems in the highly industrialized Beaumont/Port Arthur area which is closer to Louisiana sources. Fourth, TCEQ and other stakeholders have a wealth of data showing how ozone has formed on the days when the HGB Area has high ozone – and these data, in particular back trajectories, do not indicate that Louisiana emissions are the sources of ozone formation, but rather suggest local sources. A report to TCEQ stated:

> *We found no apparent pattern in the wind trajectories for the extreme events. These events were found to be associated with both backward wind trajectories characterized by straight air flow from distant and a more sinuous air flow that allowed for recirculation in the proximity of the sites.* ***The independence of the extremes in the trajectories patterns suggests that the sources are very local.***

See: FINAL REPORT, Source Attribution and Emission Adjustment Study, Battelle Memorial Institute (2005).

[4] The Beaumont-Port Arthur Area has 9 ozone monitors.

http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/Source_Attribution_and_Emission_Adjustment_Study_Task1.pdf.

Of perhaps greater importance, the EPA predictions that Louisiana emissions affect 5 monitors in HGB are based on modeling that is proved to be inaccurate by comparison of the projected values to actual values. The following tables shows the EPA projections compared to actual monitored ozone data for these five monitors.

Table 1: Comparison of EPA Projected 2012 Design Values to Actual Design Values for the Three HGB Monitors Alleged to be "Significantly Impacted" by Louisiana Emissions (in parts per billion "ppb")

Monitor	EPA CSAPR **Projected** 2012 DV	Actual 2011 DV (difference)	Actual 2010 DV (difference)	Actual 2009 DV	Actual 2008 DV	Actual 2007 DV	Actual 2006 DV	Comments
Brazoria Co. Manvel Croix 480391004	89	86 (-3)	84 (-5)	84	85	91	96	Actual has been lower than projected for 4 yrs
Harris Co. Houston Croquet 482010051	88	77 (-11)	77 (-11)	76	80	87	94	Actual has been lower than projected for 4 yrs
Harris Co. Bayland Park 48201055	96	80 (-16)	82 (-14)	84	91	96	103	Actual has been lower than projected for 4 yrs

Table 2: Comparison of EPA Projected Maximum Design Value to Actual Design Values for the Two HGB Monitors Allegedly Experiencing Interference With Maintenance of Attainment by Louisiana Emissions

Monitor	EPA CSAPR Projected Max 2012 DV	2011 Actual DV	2010 Actual DV	2009 Actual DV	2008 Actual DV	2007 Actual DV	2006 Actual DV	
Harris Co. Northwest 482010029	86	82 (-4)	81 (-5)	84	85	91	91	Actual has been at or lower than projected for 3 years

Monitor	EPA CSAPR Projected Max 2012 DV	2011 Actual DV	2010 Actual DV	2009 Actual DV	2008 Actual DV	2007 Actual DV	2006 Actual DV	
Harris Co. Seabrook Friendship Park 482011050	86	76 (-10)	76 (-10)	78	79	86	90	Actual has been at or lower than projected for 5 yrs

EPA's projections for 2012 should be close to 2010 and 2011 actual values – but they clearly are not. They are all biased high by 5 to 12%. This "projection" approach used by EPA is simply too inaccurate to base a program requiring the expenditure of millions of dollars and disrupting the entire Louisiana electrical distribution system.

Further, as asserted by the comments of the Louisiana Department of Environmental Quality and the Louisiana Chemical Association which were adopted by reference in the comments of the LPSC staff to EPA, the EPA's model inputs assumed over 125,000 thousand tons more NOx than is contained in the Louisiana LDEQ certified inventory. Although EPA made some corrections to the inventory as requested by commenters, EPA still is using an inventory assuming > 125,000 tons per year of NOx emissions more than is believed by LDEQ and LCA to be correct. Because roughly half of these emissions occur during ozone season, the EPA ozone season projection is likely to be 60,000 to 70,000 tons too much. LDEQ's emission inventory has been certified and accepted for purposes of ozone modeling by EPA Region 6 and is based on correct use of all EPA protocols. The amount of tons in dispute is greater than the entire budget allocated to Louisiana EGUs; thus this is a critical issue that must be resolved. At the present time, LEUG's review of the EPA's final rulemaking documents do not clearly indicate why some of the errors pointed out by LDEQ and LCA were not corrected in the EPA projections. For example, it appears that the projections for nonroad NOx emissions by EPA are still much higher than LDEQ's projections, with no discussion of why EPA rejected LDEQ's methodology. In addition, it appears that EPA did not properly correct the data base for point sources to account for the NOx emissions reductions resulting from LDEQ rule LAC 33:III.Chapter 22 and EPA did not appropriately deduct from the emissions inventory some emissions reductions mandated by state and federal consent decrees.

The LCA comments adopted by reference in the LPSC staff comments stated as follows with respect to the inventory issue:

> *The EPA 2005 Louisiana emissions inventory for NOx is significantly different from the 2005/2006 Louisiana state-wide emissions inventory used by the Louisiana Department of Environmental Quality (prepared by their consultant Environ International) for LDEQ's modeling support for its request to redesignate the Baton Rouge Area to 8-hour*

ozone attainment.[5] ***EPA's inventory of NOx exceeds the Louisiana inventory by 174,465 tpy.***

The Baton Rouge area attainment demonstration contained a NOx emissions inventory for Louisiana for 2005 and 2006. The table below shows Louisiana's 2005 NOx emissions inventory from that attainment demonstration compared to the proposed Transport Rule's NOx projected emissions inventory for 2005 from table IV.C-2 of the Preamble to the TR/FIP proposal.

LCA Table 3: Comparison of EPA TR and LADEQ NOx Emission Inventory

Source	*EGU Point*	*NonEGU Point*	*Total Point*	*Nonpoint*	*Nonroad*	*Onroad*	*Fires*	*Total*
2005 Transport Rule Base Case	*63,791*	*165,162*	*228,953*	*27,559*	*301,170*	*112,889*	*3,254*	*673,824*
2005/2006 Louisiana SIP support			*222,651*	*28,466*	*114,029*	*96,728*	*37,485**	*499,359*
Difference TR to LA			*+6,302*	*-907*	*+187,141*	*+16,161*	*-34,231*	*+174,465*

**These are total biogenic NOx emissions.*

The comments then went on to discuss a number of reasons why it was believed that the NOx inventory proposed by EPA was inaccurate. The final CSAPR rule made some adjustments, but is still inaccurate. The total NOx used in the final rule's "base case" modeling was still 626,542 (more than 125,000 tons over Louisiana's certified inventory). See Technical Support Document for the final emission inventory http://www.epa.gov/airtransport/pdfs/EmissionsInventory.pdf. EPA's projection for 2012, with EGU's controlled, was 494,774 tons per year – significantly more than projected by LDEQ and significantly more than the current actual inventory. Thus, if EPA had used the certified LDEQ Louisiana inventory rather than its projected inventory for input into the air quality modeling, it is extremely likely that there would be no projected impact on Texas whatsoever. EPA should be required to revise the inventory and conduct new modeling.

EPA's IPM is Inappropriate for This Application and Should Not Be Used to Determine Contributions to Other States or for Establishing Budgets

[5]Technical Support Document: Modeling to Support the Baton Rouge, Louisiana, 8 Hour State Implementation Plan, prepared by Environ International Corp. and Eastern Research Group for the Louisiana Department of Environmental Quality, (March 2009) , available at http://www.deq.louisiana.gov/portal/LinkClick.aspx?fileticket=AKLhO7ZOTMU%3d&tabid=2982 (hereinafter cited as the "LDEQ 8HR SIP TSD").

The LPSC should reconsider the comments filed by the LPSC staff and other Louisiana entities concerning the inaccurate predictions of the Integrated Planning Model ("IPM") used by EPA to make both its base case predictions and its final remedy projections. The IPM is a regional economic model that has been proven to make extremely inaccurate predictions with respect to the utilization of Louisiana Electric Generating Units ("EGUs"). EPA used Version 4.10 of the IPM model for the final rule. Through use of the IPM v. 4.10, for EPA projected that even without the Clean Air Interstate Rule ("CAIR") or the Cross State Air Pollution Rule, Louisiana EGUs would emit only 13,400 tons of NOx during the ozone season in 2012, and only 13,900 tons of NOx during the ozone season in 2014. EPA's "remedy" projected EXACTLY the same amount of NOx being emitted from Louisiana EGUs. EPA projected that because Louisiana EGUS were going to be utilized at such low rates, or for some EGUs, that they would not be utilized at all, NO RETROFITTING of any of the Louisiana EGUs would be required. Thus, EPA did not include the cost of retrofitting any Louisiana units in its cost analysis for the cost of the rule.

In fact, in 2010, Louisiana EGUs emitted 21,397 tons of NOx during ozone season. This level was very consistent with the 5 year average emissions from the same units. Moreover, 2011 year to date data indicate that 2011 emissions are on par with 2010 emissions. EPA data do not show that any of these units would be required to meet any more stringent NOx limitations over the next year as a result of consent decrees or environmental rules. ***This means that these units, which are already compliant with CAIR, are emitting about 8,000 tons per year more than EPA's IPM v. 4.10 projections predict. This is a critical point. EPA did not make any determination that these EGUs needed additional control in order to avoid impacts on the HGB Area. Instead, EPA simply projected that because of economic reasons completely unrelated to environmental reasons that the Louisiana EGUs would be utilized less, and so EPA limited them to this amount. There is absolutely no real relationship between the amount of "reduction" that EPA is requiring these EGUs to meet and the air quality in the HGB Area. As noted above, all monitors in the HGB Area (not just the 5 monitors allegedly impacted by Louisiana emissions) met the 1997 Ozone NAAQS during 2009 and 2010, while Louisiana EGUs were emitting 21,397 tons per ozone season of NOx. There is no rational basis to now limit the Louisiana EGU budget to only 13,400 tons per year as is required by CSAPR.***

The LPSC should request that EPA reconsider the rule by reviewing actual data on utilization of Louisiana EGUs during 2011 year to date and calendar year 2010. Actual heat input data and NOx emissions data from 2011 year-to-date and data from 2010 was not available prior to the close of the public comment period. Such data show vastly different results than were projected by the IPM v. 4.10 base case and final remedy 2012/2014 modeling. Such discrepancies are noted in the Table attached as Exhibit 1.

EPA Did Not Provide for Adequate Notice of The Louisiana Budget and Final Allocations and Should Reopen the Comment Period on Reconsideration of CSAPR

Because EPA did not propose to require any retrofits or controls on Louisiana EGUs as part of the proposed rule, or any of the Notices of Data Availability ("NODAs"), the LPSC should request that EPA re-open notice and comment rulemaking to allow comment on the required controls and/or projected early retirement for Louisiana EGUs and the ability of Louisiana EGUs to meet these requirements by the 2012 ozone season. EPA's budget, which is based on unrealistic modeled projections, will, in effect, require Louisiana EGUs to retrofit or cease operation. There is no source of allocations that can be traded. All Louisiana EGUs got allocations that were either exactly what level was needed, or less – none got more. **These EGUs cannot design, permit, and implement retrofits prior to the 2012 ozone season.** LUS is particularly concerned with the approach that EPA took with respect to making the determination as to the quantity of emissions reductions required of Louisiana EGUs in order to remove "significant contribution" or "interference with maintenance" of the ozone standard in the Houston area. EPA's approach is described at 76 Fed.Reg. 48263. This approach was not discussed in the proposed Transport Rule, nor was the IPM model run entitled "TR_uncontrolled _ozone_states_Final" made available for public comment.

The LPSC should request that EPA reconsider the rule such that if EPA maintains that Louisiana EGUs should still be subject to the rule for ozone season NOx reductions, that EPA revise the NOx budget for Louisiana to higher and more accurate levels commensurate with actual operations of the Louisiana EGUs (perhaps basing the budget on the highest of the highest of the last 3 years or on the average of the last 3 to 5 years actual heat input rates). In any case, EPA should establish the ozone season NOx budget for Louisiana at the level that is demonstrated to be **necessary** to prevent significant impact on 1997 ozone nonattainment in the HGB Area or to avoid interference with maintenance with the ozone standard in such Area.

EPA Should Stay the CSAPR

For all of the reasons stated in these comments, LUS urges LPSC to request EPA to stay the CSAPR during the period of reconsideration and allow CAIR to remain in place during that time. The LPSC should request that EPA should reconsider the effective date for implementation of the rule for at least three additional years to allow time for Louisiana EGUs to effectively plan for implementation of the rule without disruption of the electrical markets within the state and without devastating the economy of Louisiana. Further, the LPSC should request that EPA allow the State of Louisiana additional time to prepare and submit for approval a State Implementation Plan in lieu of the Federal Implementation Plan.

12) What unique regulatory issues should the LPSC examine that may be associated with utilities compliance with CSAPR? Should these issues be addressed within the current docket or other rulemaking and/or ratemaking proceedings?

LUS is not an LPSC regulated entity, and therefore is not responding to this question.

13) Please provide any additional information that you believe will assist the Commission in its decision whether or not to pursue a legal remedy in this matter.

LUS appreciates the opportunity to comment on the impact of CSAPR and urges LPSC to take all appropriate action to prevent the implementation of CSAPR.

RESPECTFULLY SUBMITTED:

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the Lafayette Utilities System's Revised Comments have been served by electronic mail and/or by U.S. mail, postage prepaid, on all parties on the Official Service List.

Baton Rouge, Louisiana this 19th day of August, 2011

[i] The allocations are the same for 2012 Phase I of CSAPR and 2014 Phase II of CSAPR.
[ii] The allocations are the same for 2012 Phase I of CSAPR and 2014 Phase II of CSAPR.

Exhibit 1

Table: Louisiana EGU Facilities Actual[i] Ozone Season NOx Compared to July 2010 Proposed Transport Rule Allocations,[ii] and to September 2010 NODA IPM v. 4.10 Revised Transport Rule Allocations[iii] and to Final July 2011 Cross-State Air Pollution Rule (CSAPR) Allocations[iv]

(in tons per year)

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012[v]	Is Final Allocation Sufficient to Cover Actual Emissions?
Acadia Power Station 55173		324	679	172	Yes
2010 (all 4 units ran during summer)	78.7				
2009	161.5				
2008	159.7				
2007	123.5				
2006	111.6				
2005	96.7				
Arsenal Hill Power 1416		0	60	47	No
2010	67.6				
2009	14.2				
2008	52.3				
2007	48.4				
2006	50.5				

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012	Is Final Allocation Sufficient to Cover Actual Emissions?
2005	79.3				
Bayou Cove Peaking Power Plant 55433		0	2	13	Yes, basically
2010	4.2				
2009	7.8				
2008	14.5				
2007	1.0				
2006	0.8				
2005	0.5				
Big Cajun 1 1464		15	3	30	Yes, basically
2010	17.0				
2009	42.0				
2008	28.5				
2007	10.1				
2006	6.7				
2005	2.6				

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012 v	Is Final Allocation Sufficient to Cover Actual Emissions?
Big Cajun 2 6055		5,186	5,449	2,842	No
2010	5,265.0				
2009	4,733.1				
2008	5,006.9				
2007	5,631.9				
2006	5,669.2				
2005	5,305.4				
Calcasieu Plant 55165		17	5	57	Almost - about 6 tons short
2010	62.1				
2009	25.6				
2008	34.7				
2007	18.4				
2006	13.6				
2005	5.1				
Carville Energy Center 55404		17	95	163	Yes
2010	163.0				
2009	134.7				

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012	Is Final Allocation Sufficient to Cover Actual Emissions?
2008	99.9				
2007	144.9				
2006	144.0				
2005	115.1				
D G Hunter 6558 (City of Alexandria)		0	0	11	No
2010	0				
2009	306.8				
2008	33.1				
2007	1.0				
2006	8.2				
2005	0.0				
Doc Bonin 1443 (Lafayette Utilities Service)		328	268	128	No
2010	234.9				
2009	162.7				
2008	68.6				
2007	24.2				
2006	48.9				

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012	Is Final Allocation Sufficient to Cover Actual Emissions?
2005	486.6				
Dolet Hills Power Station 51		4,884	3,031	1,056	No
2010	2,134.6				
2009	1,986.5				
2008	2,213.4				
2007	2,160.7				
2006	4,606.5				
2005	5,694.9				
Dow St Charles Operations 50152		20	16		Source is not an EGU and was deleted as requested
Coughlin (Evangeline) Power Station 1396		403	33	231	Yes
2010	62.5				
2009	134.8				
2008	167.3				
2007	140.9				
2006	212.4				
2005	162.1				

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012	Is Final Allocation Sufficient to Cover Actual Emissions?
[redacted]		[redacted]	[redacted]		[redacted]
[redacted]		[redacted]	[redacted]		[redacted]
Hargis-Hebert Electric 56283 Lafayette Utilities Service		8	1	38	Almost – just 1 tpy short
2010	38.6				
2009	23.5				
2008	32.0				
2007	30.2				
2006	23.0				
Houma 1439		0	0	21	No
2010 (still operating 2011)	7.1				
2009	68.5				
2008	65.0				
2007	18.9				
2006	67.5				
2005	61.0				

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012	Is Final Allocation Sufficient to Cover Actual Emissions?
Lieberman Power 1417		0	0	55	No
2010	42.6				
2009	103.4				
2008	49.3				
2007	48.0				
2006	44.4				
2005	63.9				
Little Gypsy 1402		0	0	685	No
2010	1,680.0				
2009	1,971.0				
2008	1,633.7				
2007	1,290.6				
2006	821.1				
2005	1,767.5				
Louisiana 1 1391 (ExxonMobil)		28	27	579	No
2010	783.7				
2009	522.2				

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012	Is Final Allocation Sufficient to Cover Actual Emissions?
2008	631.8				
2007	596.0				
2006	602.8				
2005	669.2				
Michoud 1409		0	0	592	No
2010	767.8				
2009	835.2				
2008	1,086.5				
2007	1,423.0				
2006	830.6				
2005	1,441.4				
Morgan City Electrical Gen Facility 1449		0	0	34	Yes, for all but 1 of last 6 years
2010	22.7				
2009	19.1				
2008	18.7				
2007	21.7				
2006	72.7				
2005	26.8				

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012 v	Is Final Allocation Sufficient to Cover Actual Emissions?
Natchitoches 1450		0	0	0	No change
2010 did not run, did not run in 2011	0.0				
2009	0.0				
2008	1.2				
2007	0.7				
2006	0.8				
2005	0.5				
Nelson Industrial Steam Co "50030 (Citgo, ConocoPhillips, Sasol)		566	395	415	Yes
2010	349.2				
2009	362.1				
2008	418.2				
Ninemile Point 1403		0	0	1,445	No
2010	4,908.4				
2009	2,821.6				
2008	4,733.0				
2007	5,630.1				

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012	Is Final Allocation Sufficient to Cover Actual Emissions?
2006	3,461.1				
2005	4,293.4				
Ouachita Plant 55467		285	86	78	Yes
2010	43.1				
2009	23.6				
2008	52.7				
2007	77.5				
2006	75.7				
2005	39.6				
PPG Powerhouse C 50489		72	64		Source is not an EGU; was deleted as requested
Perryville Power Station 55620		136	37	68	Yes
2010	66.0				
2009	51.7				

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012	Is Final Allocation Sufficient to Cover Actual Emissions?
2008	47.6				
2007	45.7				
2006	48.3				
2005	48.8				
Plaquemine Cogen 5419 (Dow)		205	21	204	Yes
2010	158.1				
2009	151.9				
2008	161.8				
2007	134.2				
2006	147.2				
2005	153.5				
R S Cogen 55117 (PPG)		14	46	329	Yes
2010	287.6				
2009	320.3				
2008	280.6				
2007	306.3				
2006	313.9				

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012 [v]	Is Final Allocation Sufficient to Cover Actual Emissions?
2005	315.2				
R.S Nelson[vii] 1393		2,279	1,584	1,381	No
2010	2,021.3				
2009	2,887.6				
2008	2,660.8				
2007	2,523.9				
2006	2,767.0				
2005	2,563.4				
Brame Energy Center (f/k/a/ Rodemacher) 6190		4,761	2,863	1,266	No
2010 [Unit 1 gas – 429.8] [Unit 2 coal - 1,133.9] [Unit 3-1 petcoke – 140.3] [Unit 3-2 petcoke – 153.6]	1,857.6				
2009	1,668.4				
2008	2,965.0				
2007	3,023.3				

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012	Is Final Allocation Sufficient to Cover Actual Emissions?
2006	4,118.6				
2005	3,572.4				
Shell Chemical 56248		0	0	n/a	Not an EGU was deleted as requested
Sterlington 1404		60	63	8	No
2010 (Unit 10 did not run in 2010 and not running 2011 has not run since 2006)(other units still running 2011)	6.0				
2009	1.9				
2008	3.1				
2007	42.2				
2006	33.4				
2005	367.6				
T J Labbe 56108 (Lafayette Utilities Service)		6	1	40	Yes/almost – short about 1 ton
2010	40.7				
2009	7.9				
2008	34.1				
2007	24.1				

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012	Is Final Allocation Sufficient to Cover Actual Emissions?
2006	28.9				
2005	3.8				
Taft Cogen Facility 55089 (Occidental)		26	45	250	Yes
2010	237.0				
2009	182.5				
2008	229.3				
2007	240.5				
2006	201.5				
2005	202.2				
Teche Power Station 1400		608	0	241	No
2010	583.8				
2009	523.0				
2008	368.5				
2007	496.5				

Facility Name - Facility ID (ORISPL)	Actual Ozone Season NO_x	Original Proposed Transport Rule Allocations	Revised NODA Summer NOx Allocation (IPM v. 4.10)	CSAPR NOx Ozone Season Allocation 2012	Is Final Allocation Sufficient to Cover Actual Emissions?
2006	322.9				
2005	530.5				
Waterford 1 & 2 8056		0	0	349	No
2010	548.1				
2009	304.8				
2008	519.4				
2007	393.4				
2006	337.7				
2005	905.0				
Willow Glen 1394		0	0	202	No
2010	679.2				
2009	367.4				
2008	159.9				
2007	139.2				
2006	75.4				
2005	470.1				

[i] Aetual data is from the Environmental Proteetion Ageney, Clean Air Markets Data and Maps, "Where You Live" Link for Louisiana Facilities and/or "Emissions" link's from http://camddataandmaps.epa.gov/gdm/. Such data is garnered by Continuous Emission Monitors and Fuel Monitor eertified by the facility's designated representative and reported quarterly to EPA under the Aeid Rain and/or CAIR programs.

[ii] The EPA Alloeations are derived direetly from the Environmental Protection Agency Teehnieal Support Document for the Transport Rule, Budgets and Allocations – Detailed Unit-Level Data (Excel), BADetailedData.xls, available at http://www.epa.gov/airtransport/techinfo.html.

[iii] The EPA Alloeations are derived directly from the Environmental Protection Agency Technical Support Doeument for the Transport Rule, Budgets and Allocations – Detailed Unit-Level Data (Excel), BADetailedData.xls, at tab "Allocations and Rate Limits", available at http://www.epa.gov/airquality/transport/teeh.html.

[iv] The EPA Allocations are derived directly from the Environmental Proteetion Ageney Technical Support Document for the CSAPR, Final CSAPR Unit Lcvel Alloeations under the FIP, available at http://www.epa.gov/airtransport/pdfs/UnitLevelAlloc.pdf.

[v] Thc allocations are the same for 2012 Phase I of CSAPR and 2014 Phase II of CSAPR.

[vi] NISCO Units 1 and 2 were erroncously shown in the Septembcr 2010 NODA as being a part of the RS Nelson faeility. The allocations for these two units are corrcctly identified in the more recent NODA of January 2011. NISCO began reporting to EPA Clean Air Markets Database in 2008. Actual emissions data for prior year is not available from Clcan Air Markets Databasc. Site wide data which includes other units than the 2 EGUs but not unit data is available in LDEQ annual emissions inventory.

[vii] RS Nelson IPM 4.10 allocations have been adjusted to refleet removal of thc two Nelson Industrial Steam Co. units.

SPP Southwest Power Pool

HELPING OUR MEMBERS WORK TOGETHER
TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE

Nicholas A. Brown, President & CEO

VIA ELECTRONIC SUBMISSION AND FIRST CLASS MAIL

July 19, 2011

Water Docket
U.S. Environmental Protection Agency
Mail Code: 4203M
1200 Pennsylvania Ave., NW
Washington, DC 20460

EPA Docket Center
U.S. Environmental Protection Agency
Mail Code: 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460

Re: National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities; Docket ID No. EPA-HQ-OW-2008-0667

National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Docket ID Nos. EPA-HQ-OAR-2009-0234 and EPA-HQ-OAR-2011-0044

Dear Sir or Madam:

Southwest Power Pool, Inc. (SPP) appreciates the opportunity to comment and respectfully submits the attached report entitled, "Review of the Potential Reliability Impacts of Proposed EPA Regulations Impacting Generation in the SPP Footprint", dated July 19, 2011, in response to the U.S. Environmental Protection Agency's (EPA) proposed rules issued in the above-captioned dockets. SPP's preliminary assessment is based on a similar study performed by ERCOT which found comparable results. SPP's cursory analyses identify substantial reliability and cost impacts under credible scenarios with extremely conservative inputs and assumptions, particularly in light of the recently released EPA Cross-State Air Pollution Rule (CSAPR) which was not considered in this assessment.

SPP is an Arkansas non-profit corporation with its principal place of business at 415 N. McKinley, Suite 140, Little Rock, Arkansas 72205. Currently, SPP has 64 members serving approximately 15 million customers in a 370,000 square mile service territory covering all or part of the following states: Arkansas, Missouri, Kansas, Oklahoma, Louisiana, Mississippi, Nebraska, New Mexico and Texas. SPP's members include investor-owned utilities, municipals, cooperatives, state authorities, independent power producers, power marketers, independent transmission companies, as well as a contract participant. SPP is a Federal Energy Regulatory Commission (FERC) approved Regional Transmission Organization (RTO) and administers open-access transmission services across the SPP region under the terms of SPP's Open Access Transmission Tariff. As an RTO, SPP plans for and functionally controls the transmission infrastructure committed to it and administers a competitive real-time wholesale electricity marketplace.

As outlined in the paragraphs that follow, SPP is concerned that the timeframe for implementation of the proposed rules may not provide generator operators sufficient time to bring their facilities into compliance, and they would be prohibited from operating until compliance activities can be completed. Should this occur, threats to the reliable operation of the grid will occur.

While SPP's initial assessment has focused on coal and gas units and select EPA rules similar to the ERCOT assessment, other pending requirements – carbon dioxide regulations for example – could have major impacts on future resource plans, system reliability, and economics. It is important to note this initial assessment did not consider impacts the reciprocating internal combustion engines (RICE) regulations may have on the potential loss of small units which many municipalities have relied upon. Elimination of those units could create local congestion challenges and require both transmission expansion and local programs to keep the lights on. Similarly, SPP did not consider the impact of Regional Haze requirements and the most recently published Cross-State Air Pollution Rule, which will exacerbate impacts on the system and SPP's ability to maintain adequate generating capability and reserves in the SPP footprint.

Based on this cursory assessment, which seems conservative given recent developments, it appears that EPA regulations could prevent reliable operation of the SPP RTO. Further impacts may occur, including failure to meet the requirements set forth by the North American Electric Reliability Corporation which were approved by FERC. SPP's findings and conclusions are not intended to exaggerate the system impacts, but rather to point out the possible types of adverse outcomes that may result in worst case scenarios as defined in this assessment.

SPP is concerned that the timeframe for compliance with the proposed rules, should they be approved, may be more aggressive than what can be achieved by the industry. Should this be the case it may adversely impact grid reliability due to the sudden required retirements and outages of units. At this point, SPP is aggressively monitoring several areas of its system where temporary mothballing of facilities appears possible and may lead to unstable, and hence unreliable, operating conditions. SPP encourages the EPA to work with generation owners to develop flexible compliance schedules to ensure equipment installation is completed in a timely, safe, reliable and cost-effective manner without an arbitrary deadline. Compliance plans developed in a collaborative manner may lessen the negative impact and/or prevent the unavailability of labor, parts, and other resources that may result from an arbitrary deadline. Such an approach would also ease concerns over grid instability caused by mass outages on generators to install the required equipment.

Furthermore, SPP is concerned that sufficient time will not be available to complete transmission construction activities necessary to mitigate the prohibited operation of certain generators and to complete the construction of replacement resources. As SPP becomes aware of units removed from service due to compliance with these new regulations, it will work diligently to plan and direct the transmission construction necessary to mitigate any resulting reliability issues on the SPP transmission system. However, as Transmission Customers within the region remove units from service and secure new replacement capacity, SPP is concerned as to the uncertainty of being able to identify the needed upgrades and place those new lines in service. SPP is responsible for overseeing the reliable operation of the SPP transmission system and is concerned that, in the event SPP is unable to construct the necessary lines in time and units are unable to operate due to these additional EPA restrictions, the SPP transmission system may be placed in an unreliable operating state or one that necessitates firm load curtailments/customer outages.

As a result of these concerns, SPP has two specific recommendations:

- First, SPP recommends that the EPA provide a gradual compliance schedule that allows the industry time to meet the proposed requirements in a reliable, safe and economic manner. Working with the industry to institute these changes will help preserve reliable system operations and also allow for a more gradual integration of the costs of compliance that could significantly mitigate reliability issues and sudden increases in consumer electricity prices.
- Second, SPP recommends that the EPA include in its rules a temporary waiver mechanism under which the affected generator owner, could seek an extension to allow for the continued operation of a generator while solutions, such as transmission expansion or demand response programs, can be assessed and approved by SPP and other transmission service providers.

Although these recommendations are based solely upon SPP's initial assessment, they appear to be prudent under any foreseeable conditions that may occur.

Please do not hesitate to contact me should you have questions or would like to request additional information.

Respectfully submitted,

Nicholas A. Brown
President & CEO
(501) 614-3213 • Fax: (501) 664-9553 • nbrown@spp.org

cc: SPP Board of Director, Members Committee, Strategic Planning Committee
State Regulators and Federal Legislators in AR, KS, LA, MO, MS, NE, NM, OK, and TX

Review of the Potential Reliability Impacts of Proposed EPA Regulations Impacting Generation in the SPP Footprint

July 19, 2011

SPP Southwest Power Pool

Table of Contents

Introduction

During its May 5-6, 2011 meeting, the Strategic Planning Committee directed SPP staff to conduct an independent study to assess the reliability impacts of a group of proposed Environmental Protection Agency (EPA) regulations that will potentially impact generation in the SPP footprint. As in a similar May 2011 ERCOT study, the assessment's scope is limited to the regulations identified below. Confining the impacts to a specific or proposed regulation at a specific point in time, however, is challenging.[1]

Clean Water Act – Section 316(b)

Section 316(b) of The Clean Water Act is intended to limit entrainment and impingement that occurs during the cooling process at electrical generation facilities. The proposed rule[2] affects existing power plants that generate electricity and withdraw at least 2 million gallons per day of cooling water, used to dissipate waste heat. The EPA estimates that approximately 670 power plants will be affected, although some facilities may already employ technologies that comply with proposed impingement requirements.[3] Comments are due on or before July 19, 2011, and a final rule is expected in July 2012 with commensurate compliance beginning in eight years.

Clean Air Act – HAP Rule

The EPA-proposed mercury and air toxics standards consist of national emissions standards for hazardous air pollutants (HAP) from coal- and oil-fired electric generating units under section 112(d) of the Clean Air Act and revised new source performance standards for fossil fuel-fired units under section 111(b) of the Clean Air Act.[4] These regulations apply to coal- and oil-fired electric generating units, and are expected to decrease by 91% the level of mercury these facilities currently release. Comments are due on or before August 4, 2011, and a final rule is expected in November 2011. Compliance is mandatory within three years, although an additional year may be granted.

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[1] Although notable, staff's assessment does not address the national emission standards for hazardous air pollutants for reciprocating internal combustion engines (RICE), which were the subject of EPA Docket ID No. EPA-HQ-OAR-2008-0708. The final RICE rule was made effective May 9, 2011.

[2] National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, 76 Fed. Reg. 22174 (proposed April 20, 2011) (to be codified at 40 C.F.R. pts. 122 and 125).

[3] Answers to Common Questions about the Proposed Rule, March 28, 2011, accessed http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/qa_proposed.pdf, July 1, 2011.

[4] National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 76 Fed. Reg. 24976 (proposed May 3, 2011) (to be codified at 40 C.F.R. pts. 60 and 63).

Clean Air Transport Rule

The Clean Air Transport Rule (CATR)[5], applicable to 31 eastern states and the District of Columbia, is intended to reduce air pollution, specifically the transportation of ozone and fine particle matter across states. Originally proposed on July 6, 2010 as a replacement to the Clean Air Interstate Rule, the CATR contains two phases that would reduce nitrogen oxide (NO_x) and sulfur dioxide (SO_2). This rule applies to facilities with more than 25 megawatts (MW) of capacity and would impact more than half of generation units in the SPP footprint. Compliance with Phase I begins in 2012.

Coal Combustion Residuals Rule

The Coal Combustion Residuals Rule[6] contains several alternatives for dealing with waste ash produced during the generation of electricity. Both proposals by the EPA use the Resource Conservation and Recovery Act to manage disposal of coal ash in a more stable state than current methods of impoundment. The first two methods involve federal permitting and monitoring requirements. The third allows states to interpret national permitting guidelines. According to the EPA's Regulatory Impact Analysis, over the next fifty years the first two methods could result in higher costs than the third method.

Approach

It is unclear how these regulations will affect the industry. SPP's Integrated Transmission Plan 10 (ITP10) Scenario 2 regarding EPA rules retires most coal units less than 200 MW which aggregate to a total of 2.6 gigawatts (GW) of capacity within SPP. Earlier reports provided results ranging from 1 to 5 GW of retired capacity in the SPP footprint. Such scenarios provide a spectrum from potentially minor to moderate reliability issues in the SPP footprint.

To ensure completion of this assessment for consideration within the timeframe required, staff performed an abbreviated analysis of potential reliability impacts and utilized a number of representative reports in framing its analysis. A list of these reports is set forth below:

- *Potential Coal Plant Retirements Under Emerging Environmental Regulations*, The Brattle Group, December 8, 2010;
- *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*, Edison Electric Institute, prepared by ICF International, January 2011;
- *Review of the Potential Impacts of Proposed Environmental Regulations on the ERCOT System*, Electric Reliability Council of Texas, May 11, 2011 (ERCOT Report);

[5] Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 75 Fed. Reg. 45210 (proposed Aug. 2, 2010) (to be codified at 40 C.F.R. pts. 51, 52, 72, 78, and 97).

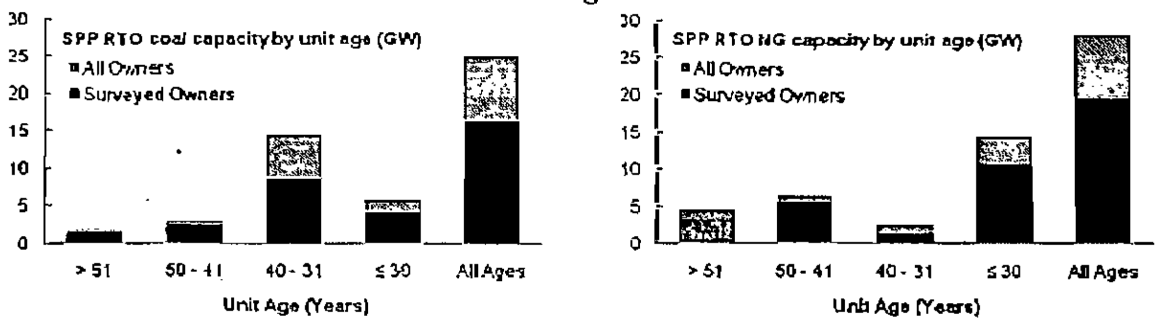
[6] Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities, 75 Fed. Reg. 35128 (proposed June 21, 2010) (to be codified at 40 C.F.R. pts. 257, 261, 264, 265, 268, 271, and 302).

- *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?*, Bernstein Research, October 2010; and
- *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*, North American Electric Reliability Corporation, October 2010.

Additionally, staff engaged representatives of American Electric Power (AEP), City Utilities of Springfield (CUS), Kansas City Power and Light Company (KCP&L), the Omaha Public Power District (OPPD), Southwestern Public Service Company (SPS), and Westar Energy, Inc. (Westar) to discuss the specific impacts these regulations may have on their respective generators. In the discussions a survey was provided. The survey requested information, by unit, of the plans held by the generation owners.

These generation owners, who account for 68% of the total coal and natural gas (NG) capacity in the SPP RTO footprint, completed a survey providing information such as unit retirement dates, derate amounts, outage timeframes and compliance dates. When appropriate, staff considered survey data to be generally representative and extrapolated to represent all coal and gas generators in the SPP footprint. Specific calculations where this extrapolation method was utilized are noted below. Chart 1, below, compares the capacity captured in these discussions with that of the entire SPP footprint.

Chart 1: 68% of SPP Coal and NG capacity was captured in discussions with generation owners



Staff incorporated into its analysis the expected unit retirements and proposed retrofits of these generation sources and created four scenarios that describe the possible reliability and economic impacts: *Best Case* scenario, *Low Estimate Case* scenario, *High Estimate Case* scenario and *Worst Case* scenario.

The first scenario, referenced as the *Best Case* scenario, used only information provided by the surveyed generation owners. No extrapolation or estimation was applied in this scenario regarding the impacted capacity.

Second, to account for capacity potentially impacted by these regulations but not surveyed, staff calculated the total unit retirements provided by survey respondents compared to the total number of units owned. A percentage of 10% was found by extrapolating the total-to-retired or retrofit units that would be impacted. This scenario is referenced as the *Low Estimate Case* scenario.

Third, to account for the spectrum of perspectives among those surveyed, further extrapolation was used solely with information from those surveyed with the highest amount of retirements and retrofits, providing a 25% scenario. This scenario is referenced as the *High Estimate Case* scenario.

In each of the above cases, 50% of the units were retired and 50% of the units were retrofitted. Surveyed generation owners are actively pursuing many detailed studies regarding the practicality and profitability of retrofitting or retiring generating units.

To account for the uncertainty surrounding this capacity, a final scenario referenced as the *Worst Case* scenario, was developed. It retires any unit currently under study and in addition to the units retired in the *High Estimate Case* scenario.

Staff considered the years 2015 and 2021 in its analysis; the former being when the HAP regulation goes into effect, and the latter being when the Clean Water Act – Section 316(b) regulation is to be in place. These dates provide important reference points that can be used to infer impacts to the SPP footprint in the intervening years. Staff acquired information about future generation capacity and total load from the U.S. Energy Information Administration (EIA) and the surveyed generation owners.

The EIA data used in this analysis included member reported wind capacity contributions, as well as demand response forecasts, in these projections. SPP members are expecting 426 MW of wind capacity contribution in 2015 and 2021, which demonstrates that SPP cannot expect significant contribution from intermittent wind resources during summer peak load conditions. In addition, SPP members are forecasting 1,200 and 1,400 MW of supply-side demand response for 2015 and 2021, respectively, that have been reflected in this analysis.

To estimate the potential cost impact of the proposed regulations on SPP generation owners, SPP prepared projections using dollar per kilowatt (kW) estimates provided in the ERCOT Report for retrofits of environmental control equipment. These expenses would be incurred if generation owners, through their ongoing analysis, determine that control equipment will be installed or upgraded to meet the regulations mitigating most of the possible retirements in the *Worst Case* scenario.

Reliability Outlook

Staff calculated capacity margins for the SPP RTO footprint to determine if generation supply will be available to meet the forecasted load and provide the reliability support required in SPP's governing documents. Capacity margin plays an important role in maintaining reliability across the grid and provides system capability to deal with unexpected interruptions to generation equipment occur, increases in demand due to extreme weather, etc. SPP calculates capacity margin by subtracting the total load from the total generation capacity, including the net of firm import and export obligations, divided by the total capacity.

SPP Criteria require a minimum capacity margin of 12%. However, current requirements may not prove adequate in the scenarios outlined above. Many small units could be retired while existing, larger units are being retrofitted with equipment that has an unknown impact on the performance and availability of retrofitted generators.

The data utilized by staff in its evaluation of the four scenarios is presented in Tables 1 and 2.

In the *Best Case* scenario roughly 1 GW of capacity was identified by SPP stakeholders as planned for retirement, with 1 GW to be placed into outage for compliance upgrades. This amount is below the volume noted in the reports cited in the Approach section.

The *Low Estimate Case* scenario widens the scope of retirements beyond those surveyed to all SPP generation. In this case, again, there is a limited impact with 3 GW of capacity taken from service.

The *High Estimate Case* scenario utilizes a broader application of the extrapolated information. In this scenario, SPP is forecasted to fall below the minimum required capacity margin. The *High Estimate Case* also demonstrates what may happen due to the tight timeframe around the unit upgrades. If units currently undergoing detailed individual assessments by the utilities with regard to their assessment and determination of the action(s) are retired SPP is further negatively impacted by the regulations and may be unable to maintain system security. A *Business As Usual (BAU) Case* is provided for referenee.

Table 1: 2015 Reliability Outlook

	BAU	Best Case	Low Estimate	High Estimate	Worst Case
Outages		1	2	3	7
Retirements (GW)		1	1	3	3
Total Capacity (GW)	69	66	65	63	59
Capacity Margin (%)	19%	15%	15%	11%	5%
Capacity Margin (GW)	13	10	10	7	3
Shortfall (GW)				1	5

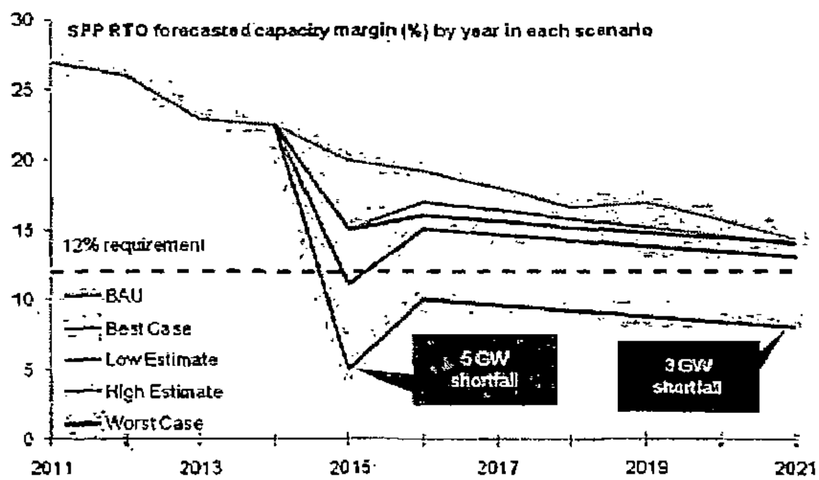
Table 2: 2021 Reliability Outlook

	BAU	Best Case	Low Estimate	High Estimate	Worst Case
Outages					
Retirements (GW)		1	2	3	7
Total Capacity (GW)	72	70	70	69	65
Capacity Margin (%)	17%	15%	14%	13%	8%
Capacity Margin (GW)	12	11	10	9	5
Shortfall (GW)					3

These evaluations were conducted for the years 2015 and 2021 and included multi-year outages necessary for the installation of control equipment, facility retirements, anticipated generation expansions and peak load levels. The expected capacity contribution of wind generation toward summer peak load obligations is relatively minor and has been included, but only at a fraction of nameplate capacity based on SPP Criteria. In addition, demand response has been included in these reliability assessments to the extent it has been reported as a resource in EIA projections.

Chart 2 presents forecasted capacity margins within SPP for the BAU and four scenarios over the next several years. The chart also illustrates the impacts within SPP if the regulations force 7 GW currently under economic evaluation and compliance review into retirement.

Chart 2: Forecasted Capacity Margins



These results are indicative of the range of possible outcomes, but may not reflect pessimistic conditions given the uncertainty which surrounds long-term projections, including future environmental regulations. In the *Worst Case* scenario, SPP expects system reliability within at least five load pockets to be adversely impacted absent aggressive transmission expansion projects, demand response or generation expansion projects.

Cost of Environmental Controls

In its assessment, staff broadly evaluated a range of costs incurred by generation owners due to potential environmental control installations. These expenses would be incurred if generation owners determine that units currently under study will be retrofitted less the expected retirements. Staff evaluated the cost to retrofit the 7 GW planned to be retired in only the *Worst Case* scenario. Table 3 outlines the associated equipment and costs.

Staff identified that approximately $8.5 billion would be required as initial investments for installation of Bag Houses (BH), Flue Gas Desulfurization equipment (FGD), and Selective Catalytic Reactors (SCR). This case assumes that all units in the worst case are retrofitted. While the estimated costs of installing new environmental equipment to ensure compliance with anticipated regulations are significant, they represent only a portion of the total cost impacts which will be realized on consumer bills. The cost impacts associated with environmental upgrades at existing plants to comply with the proposed rules are comparable to the projected transmission expansion investment which has been approved within the SPP footprint for 2011-2017. However, unlike cost recovery for transmission expansion, which has its costs allocated across the SPP footprint to a large extent, the costs for EPA compliance investments will be much more localized and varied across SPP zones.

Table 3: 2015 Retrofit Costs

	$/kW	Units Impacted	Capacity Impacted (GW)	Total Cost ($B)
BH	197	34	8	1.5
New FGD	573	39	10	5.5
FGD Upgrade	450	[illegible]	[illegible]	[illegible]
SCR	$250[3]	30	6	1.5
Total	[illegible]	42	12	8.5

These evaluations were conducted for 2015 and are based upon cost estimates provided in the ERCOT Report, supplemented by the Edison Electric Institute for SCRs, with equipment installations provided by the surveyed generation owners.

As shown in Table 3, the projected cost to retrofit, in lieu of retirement, in the *High Estimate Case* would be approximately $8.5 billion. The rate impact and justification cases involved in acquiring such funding from state utility commissions may impact the capability of the utilities to secure funding. Also, the impact on consumer bills should not be understated.

SPP's Recommendation to the EPA

While this initial assessment focuses on coal and gas units and select EPA rules, other pending requirements – carbon dioxide regulations for example – may significantly impact future resource plans, system reliability, and economics. Therefore, it is important to note that this initial assessment does not address the impacts of RICE regulations on the potential loss of small units, upon which many municipalities have relied. Elimination of those units could create local congestion challenges and require both transmission expansion and local programs to keep the lights on.

SPP is concerned that the industry may not be able to meet the abbreviated timeline for compliance with the proposed rules, should they be approved. In this case, unit outages and retirements may adversely impact grid reliability. Therefore, SPP would recommend that the EPA and generation owners collaborate to develop and meet timelines while monitoring equipment installation. Collaboration on the development of compliance plans may lessen the negative impact and/or

[3] The SCR cost is based on assumptions from the Edison Electric Institute report, estimating costs to be between $200/kW and $400/kW, and further discussion with SPP generation owners.

prevent the unavailability of labor, parts, and other resources that may otherwise result from arbitrary deadlines. Such an approach would also ease concerns over grid security caused by mass outages on generators to install the required equipment.

SPP recommends that the EPA provide a gradual compliance schedule that allows the industry time to meet the requirements in an economical, safe and reliable manner. Working with the industry to institute these changes will allow for a more gradual integration of the compliance costs that could significantly mitigate sudden increases in consumer electricity prices.

Exhibit S

Excerpt from

Comments of the Louisiana Chemical Association
on
Proposed Federal Implementation Plans to Reduce
Interstate Transport of Fine Particulate Matter and Ozone
75 Federal Register 45210 (August 2, 2010)
Docket ID No. EPA-HQ-OAR-2009-0491

October 1, 2010

Document ID: EPA-HQ-OAR-2009-0491-3527

2. EPA Overestimated Louisiana Emissions in the Emissions Inventory[42]

In addition to the above reasons for eliminating Louisiana from coverage under the Transport Rule/FIP, LCA believes that EPA significantly overestimated NOx and SO2 emissions in the 2005 emissions inventory used for this rulemaking which in turn caused an overestimation of projected impact. LCA has not had sufficient time to determine whether some of the overestimation was corrected in the IPM v. 4.10 runs, but preliminarily believes that the problems with overestimation noted below have not been corrected. Thus, LCA believes that the projected Base Case emissions should be lower than the IPM v. 4.10 projects. LCA will submit supplemental comments on the impact of use of IPM v. 4.10 on or before the October 15, 2010 deadline in the Notice of Data Availability. Thus, at present, LCA believes that EPA should correct these errors before making any final determinations in this docket.

The EPA 2005 Louisiana emissions inventory for NOx is significantly different from the 2005/2006 Louisiana state-wide emissions inventory used by the Louisiana Department of Environmental Quality (prepared by their consultant Environ International) for LDEQ's modeling support for its request to redesignate the Baton Rouge Area to 8-hour ozone attainment.[43] ***EPA's inventory of NOx exceeds the Louisiana inventory by 174,465 tpy***.

The Baton Rouge area attainment demonstration contained a NOx emissions inventory for Louisiana for 2005 and 2006. The table below shows Louisiana's 2005 NOx emissions inventory from that attainment demonstration compared to the proposed Transport Rule's NOx projected emissions inventory for 2005 from table IV.C-2 of the Preamble to the TR/FIP proposal.

LCA Table 3: Comparison of EPA TR and LADEQ NOx Emission Inventory

Source	EGU Point	NonEGU Point	Total Point	Nonpoint	Nonroad	Onroad	Fires	Total
2005 Transport Rule Base Case	63,791	165,162	228,953	27,559	301,170	112,889	3,254	673,824
2005/2006 Louisiana SIP support			222,651	28,466	114,029	96,728	37,485*	499,359
Difference TR to LA			+6,302	-907	+187,141	+16,161	-34,231	+174,465

*These are total biogenic NOx emissions.

[42] LCA has not had sufficient time to determine if the errors in overestimation discussed herein were corrected in the IPM v. 4.10 runs. Comments concerning that issue will be submitted within the comment period on the Notice of Data Availability for the IPM v. 4.10 TR runs and data files.

[43] Technical Support Document: Modeling to Support the Baton Rouge, Louisiana, 8 Hour State Implementation Plan, prepared by Environ International Corp. and Eastern Research Group for the Louisiana Department of Environmental Quality, (March 2009) , available at http://www.deq.louisiana.gov/portal/LinkClick.aspx?fileticket=AKLhO7ZOTMU%3d&tabid=2982 (hereinafter cited as the "LDEQ 8HR SIP TSD").

The Baton Rouge attainment demonstration was performed with EPA guidance and using EPA approved methodology. Sensitivity runs showed that the modeling using this data exhibited a very good fit to actual monitored data.[44] This leads one to believe that the LDEQ inventory is accurate. LCA believes that the LDEQ data should be used to adjust the emissions inventory for the transport rule. Specific aspects of the emission inventory are discussed further below.

With respect to SO2, EPA estimated the following 2005 emissions inventory for Louisiana (from EPA Preamble to the TR/FIP Table IV.C-1**):**

State	TR Case	EGU	NonEGU	NonPt	NonRd	OnRd	Fires	Total
Louisiana	2005	109,851	165,737	2,378	73,233	2,399	892	354,489

*****Note: Total point source emissions from EGU/Non-EGU = 275,588 tpy per this projection

EPA's projections for the non-road category show Louisiana to have the second highest SO2 inventory in the nation, just behind Florida, and ahead of Texas and North Carolina, the states with the next two highest emission levels for the 2005 SO2 non-road emissions inventory. Because much of the non-road category is based on population estimates, it is difficult to believe that a state with a population the size of Louisiana (ranked 25th) has non-road emissions larger than those from Texas (ranked 2nd).[45] Further, the total from EGU and Non-EGU point sources together exceeds the Louisiana certified emissions inventory for point sources for 2005 that is required by the CAA. While LDEQ does not have a readily available 2005 statewide SO2 emissions inventory for review, LCA believes that EPA overestimated both the point source and nonroad SO2 emissions as discussed below.

a. Nonroad Emissions

The largest discrepancy between the LDEQ 2005/2006 SIP and EPA 2005 TR/FIP baseline NOx inventories was in the nonroad emissions category. Nonroad emissions come from such equipment as:

Agricultural equipment, such as tractors, combines, and balers;
Airport ground support, such as terminal tractors and supply vehicles;
Construction equipment, such as graders and back hoes;
Industrial and commercial equipment, such as fork lifts and sweepers;
Residential and commercial lawn and garden equipment;

[44] *Id*.

[45] U.S. Census Bureau, GCT-T1-R. Population Estimates (geographies ranked by estimate)
Data Set: 2009 Population Estimates, http://fastfacts.census.gov/servlet/GCTTable?_bm=y&-geo_id=01000US&-_box_head_nbr=GCT-T1-R&-context=gct&-ds_name=PEP_2009_EST&-tree_id=4001&-_lang=en&-format=US-40S&-_sse=on (last visited Sept. 25, 2010).

Logging equipment, such as shredders and large chain saws;
Recreational equipment, such as off-road motorbikes and ATVs; and
Recreational marine vessels, such as power boats
Commercial marine vessels
Locomotives
Aircraft

In developing its inventory, LDEQ appears to have used the same EPA tools as did EPA for all categories except aircraft, locomotives and marine vessels. The TSD for Modeling Support in which the LDEQ's inventory is discussed states: "The EPA's National Mobile Inventory Model (NMIM) model was used to generate Louisiana statewide parish-level off-road equipment emissions estimates for June 2006. NMIM is a tool developed by EPA for estimating on-road and nonroad emissions by county for the entire U.S. to support NEI updates. NMIM incorporates EPA's final NONROAD2005 model, which estimates monthly average day emissions from off-road equipment…."[46] However the LDEQ 8HR SIP TSD stated that Louisiana emissions for locomotives and aircraft were derived from the 2006 TCEQ inventory, which were ultimately derived from the 2002 NEI and that marine shipping emissions for the entire modeling domain were developed from CENRAP inventories.[47]

Although it does not account for the entire difference between the state and federal NOx emissions inventory differences, the primary difference appears to be in the estimated emissions from marine vessels. EPA's nonroad data is comprised of three parts: (1) Locomotives, C1 and C2 marine vessels, (2) C3 marine vessels, and (3) other nonroad (from the NMIM/NONROAD model). EPA's estimated inventory for each of these parts was as follows:[48]

Locomotives, C1, and C2 marine	177,402 tpy
C3 marine	96,369 tpy
Other nonroad	27,398 tpy

EPA indicated that its estimate for locomotives, C1, and C2 marine vessels in 2005 were carried forward from 2002 NEI emissions values and may slightly overestimate C1 and C2 marine vessel emissions. EPA requested comment on this point. The LCA has not had sufficient time

[46] LDEQ 8HR SIP TSD at pp. 206-208.

[47] *Id*. CENRAP is one of the five Regional Planning Organizations ("RPOs") across the U.S. and includes the states and tribal areas of Nebraska, Kansas, Oklahoma, Texas, Minnesota, Iowa, Missouri, Arkansas, and Louisiana. The CENRAP inventory was a focused bottom up study that CENRAP believed to be more representative of actual emissions than did the EPA existing NEI 2002.[47] Under the NEI 2002 approach, EPA basically used an old 1991 Booz Allen study and took a top-down approach to allocating emissions. This approach basically took national data, then allocated to the 150 largest ports and divided based on ratio of activity and stream miles associated with such port. EPA acknowledged this would overestimate emissions from large ports (such as those in New Orleans, Lake Charles and Baton Rouge) as small ports were not allocated any of the emissions. Thus, CENRAP's inventory was viewed as more representative of actual emissions.

[48] E-mail communication: Marc Houyoux, Group Leader, Emission Inventory and Analysis Group, Office of Air Quality Planning and Standards US/EPA, to Maureen Harbourt, Kean, Miller law firm, counsel for the Louisiana Chemical Association (Sept. 8, 2010, 04:50 C.S.T.)(attached as Exhibit 6).

to investigate the accuracy of these estimates and reserves the right to submit supplemental data on this point as the basis for this information was provided to LCA on September 8, 2010.[49] In that communication, EPA indicated that the methods used by EPA to estimate these emissions are documented online at:

ftp://ftp.epa.gov/EmisInventory/2002finalnei/documentation/mobile/2002nei_mobile_nonroad_methods.pdf. [50]

EPA indicated that for the Transport Rule analysis, revised C3 commercial marine inventory data was based on "new methods" developed by EPA's Office of Transportation and Air Quality in conjunction with the international community for regulating these ocean going vessels.[51] This new method involved using the 2002 NEI values, and then "growing" such values to 2005 based on data developed by EPA for this purpose.[52] In documentation cited by EPA, it appears that EPA replaced the NEI C3 vessel inventory from our 2002 base case emissions modeling platforms with a "modified STEEM C3 inventory."[53] These new methods are derived from a preliminary, non-peer reviewed methodology developed by EPA.[54] The new methods nearly double the projected amounts of SO2 and NOx emissions from these vessels compared to prior inventories and nearly quadruple the levels of PM2.5. The documents cited by EPA consist only of an emissions inventory conference presentation. While the approach may or may not have merit, it has not been subject to peer-review or public scrutiny, and should not be used as the underpinning for this rulemaking.

The conference presentation paper relied upon by EPA described the differences between use of EPA's 2002 NEI inventory and a proposed new "modified STEEM" method for determining the C3 marine vessel emissions inventories:

> In the NEI [2002], emissions are allocated to counties in a "top-down" methodology, from national totals of port and underway (or "inter-port") activity data (U.S. EPA, 2008). 2002 NEI C3 emissions, mapped to our 36-km air quality modeling domain (U.S. EPA, 2006) are shown in Figure 4. Spatial surrogates

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[49] *Id.*

[50] *Id*.

[51] EPA indicated in response to question from LCA that "documentation on the C3 marine approach is available in the document "category_3_commercial_marine_inventories_in_the_2002_nei.pdf" available online within a zip file: ftp://ftp.epa.gov/EmisInventory/2002finalnei/documentation/mobile/version_4_updates.zip." Email from Marc Houyoux, EPA to Maureen N. Harbourt, counsel for LCA, (Sept. 22, 2010, 10:31 CST) attached as Exhibit 7.

[52] *Id*. The approach is documented on page 38 of ftp://ftp.epa.gov/EmisInventory/2005v4/2005_emissions_tsd_07jul2010.pdf.

[53] E-mail communication: Marc Houyoux, Group Leader, Emission Inventory and Analysis Group, Office of Air Quality Planning and Standards US/EPA, to Maureen Harbourt, Kean, Miller law firm, counsel for the Louisiana Chemical Association, (Sept. 22, 2010 10:41 CST) (attached as Exhibit 7).

[54] R.Mason, P. Dolwick, P. Corey, E. Kinnee, M. Wilson, Emissions Processing and Sensitivity Air Quality Modeling of Category 3 Commercial Marine Vessel Emissions, 17th Annual International Emission Inventory Conference (June 2008) available at http://www.epa.gov/ttn/chief/conference/ei17/session6/mason.pdf.

allocate the NEI C3 emissions to grid cells that intersect actual county boundaries, which extend a very limited distance offshore. This also makes spatial allocation of NEI underway shipping activity problematic, as emissions are essentially confined to the extent of the county boundaries, not expected shipping lanes. In many cases, these county boundaries are defined as the low-tide water. In addition, NEI C3 emissions are allocated to states and counties in a similar routine as smaller Class 2 (C2) vessels. As seen in Figure 4, this assumption allocated NEI C3 emissions to waterways such as the Missouri and Ohio Rivers where C3 vessels cannot access. In contrast to the NEI C3 inventory, the 2002 modified STEEM C3 emissions in Figure 5 allows for better allocation of C3 emissions for air quality modeling; modified STEEM C3 emissions are seen at ports and the shipping lanes between ports. With U.S. county boundaries extending outwards of up to 200 nautical miles, characterization/summarization of the U.S. portion of the modified STEEM C3 emissions seen in Table 1 is possible.

As noted, use of this modified STEEM C2 methodology caused the ***national*** emissions inventory for NOx and SO_2 to more than double from previous estimates and the inventory for PM2.5 to nearly quadruple.[55]

Inventory	NOx tpy	SO2 tpy	PM2.5 tpy
2002 C3 NEI Modified STEEM	596,658	371,550	47,760
2002 C3 NEI	244,924	150,497	12,617

Further, the authors of the paper advocating the modified STEEM inventory acknowledge that emissions are likely to be overestimated for coastal counties. The paper states:

> Similar to the NEI [2002], for coastal counties, ***the county boundaries were extended into Federal waters to include those portions of the waterway network which are offshore. Because the coastal county boundaries were extended into Federal waters, this approach overestimates true county level emissions for coastal counties. This limitation is more noticeable for the STEEM inventory because it captures far more underway emissions than the NEI.***[56]

EPA indicated in response to LCA questions that "the approach of the modified STEEM inventory assigns U.S. counties to the gridded data for inland waterways and lakes, ports, and through the Exclusive Economic Zone (EEZ) up to 200 nautical miles offshore or until international water boundaries."[57] LCA has several concerns with the use of the STEEM inventory. First, LCA is concerned about use of a non-peer reviewed methodology that more

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[55] *Id*.

[56] See http://www.epa.gov/ttn/chief/conference/ei17/session6/mason.pdf at p. 4 (emphasis added).

[57] E-mail communication: Marc Houyoux, Group Leader, Emission Inventory and Analysis Group, Office of Air Quality Planning and Standards US/EPA, to Maureen Harbourt, Kean, Miller law firm, counsel for the Louisiana Chemical Association, (Sept. 22, 2010 10:41 CST) (attached as Exhibit 7).

than doubles predicted emissions for use in this rulemaking. LCA believes that critical assumptions and the methodology should be subject to peer-review and notice and public comment before using such in a rule of the magnitude of the proposed Transport Rule/FIP. LCA requests that EPA use the CENRAP data for marine vessels in lieu of the modified STEEM inventory for Louisiana.

Second, LCA is extremely concerned with the potential overestimate of C3 marine shipping emissions as being attributable to Louisiana. This is of critical importance to Louisiana with its significant coastline and volume of off-shore oil and gas and shipping activities – not only for this rulemaking docket, but also for other SIP planning and modeling activities. It appears to LCA that through use of the modified STEEM inventory, EPA is allocating certain C3 marine vessel emissions to Louisiana that are not within Louisiana jurisdiction. Under CAA § 107(a), 42 USC 7407(a), the Act provides that "[e]ach State shall have the primary responsibility for assuring air quality ***within the entire geographic area comprising such State*** by submitting an implementation plan for such State which will specify the manner in which national primary and secondary ambient air quality standards will be achieved and maintained…" By implication, the state SIP can control only the emissions and activities that exist within its jurisdiction.

The citations provided by EPA indicated that EPA used all of the C3 CMV emissions (NOx, SO2, and PM2.5) from EPA's 2005 base year that have a FIPS State code (22) attributed to Louisiana in their files as part of Louisiana's significance contribution/interference with maintenance calculations. If Louisiana does not have authority over the waterways represented by this spatial distribution and EPA included all of these emissions (59,500 tons SO2;[58] 96,000+ tons NOx) in their significance test, the contribution of Louisiana's emission total is quite likely to have been overstated.

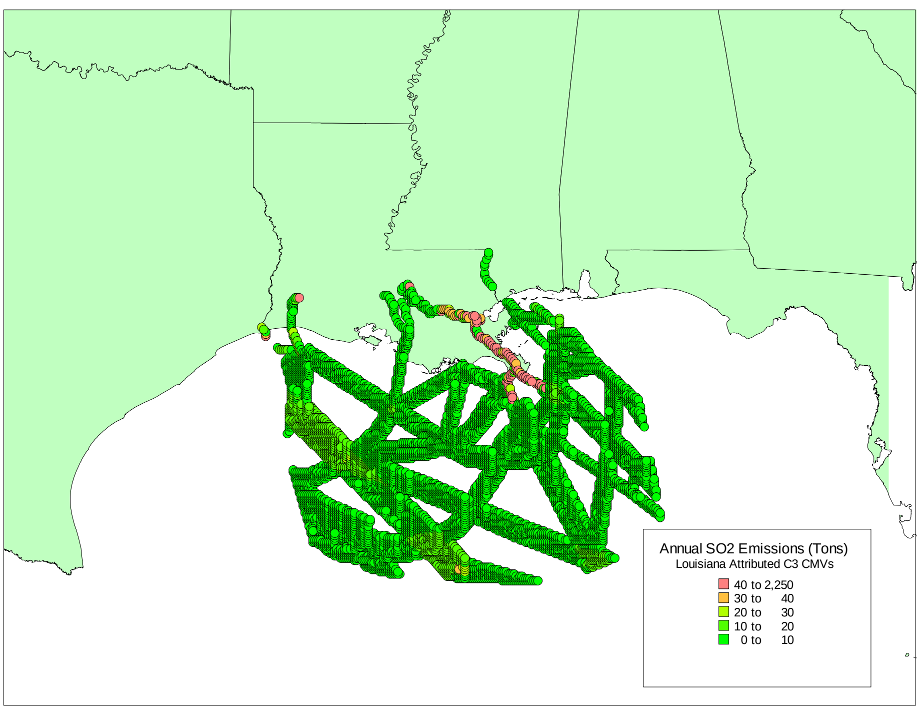
LCA questions whether all the emissions with FIPS code 22 that EPA is reporting in the C3 CMV file should be attributed to Louisiana. These emissions go as far south as the lower boundary of the modeling domain (~26 N latitude) and LCA does not believe that Louisiana political boundaries extend that far into the Gulf. ***The Louisiana legal geographic boundary only extends 3 miles from its coastline – not nearly to international water boundaries and certainly not for the hundreds of miles projected by EPA.*** The legal boundary for the Louisiana coastline was fixed by the United States Supreme Court in *United States v. Louisiana*, 389 U.S. 155 (1967). Further, the off-shore boundary between Texas and Louisiana was fixed by the United States Supreme Court in *Texas v. Louisiana* 426 U.S. 465 (1976).[59]

[58] Of the total SO2 nonroad inventory of 73,185 tpy, EPA's 2005 modeling platform actually shows annual nonroad SO2 emissions for LA to be about 13,685 tons exclusive of C3 marine vessels. Thus, EPA includes an additional 59,500 tons SO2 associated with Category 3 (C3) residual fuel commercial marine vessel (CMV) emissions.

[59] Texas's legal boundary extends "three marine leagues" from its coastline – a distance of about 10 miles, whereas the Louisiana legal boundary extends only three miles; thus, this case addressed the intersection of those boundaries. For a complete review of the history of the establishment of the legal boundary for Louisiana on the Gulf Coast, see Shalowitz and Reed, *Shore and Sea Boundaries*, Vol. 1, Part 1, available at: http://www.nauticalcharts.noaa.gov/hsd/docs/CSE_library_shalowitz_Part_one.pdf.

As further support for this position, LCA is attaching as Exhibit 11, a review of the EPA inventory for Louisiana generally and the Baton Rouge Area specifically, under the proposed Transport Rule performed by Alpine Geophysics, Atmospheric Sciences Group (September 2010). Alpine expressed concern about the overestimate of emissions from the C3 Commercial Marine Vessel inventory for Louisiana as well. As noted in that review:

> However, when plotting Louisiana's C3 CMV emissions (those sources that EPA attributed to FIPS 22), a total of 59,500 annual tons of SO_2 and over 96,000 annual tons of NO_x, we see in Figure 7 that a large portion of these emissions are located hundreds of miles off of Louisiana's coastline. The EPA has indicated that counties (parishes) were assigned these C3 CMV emissions as extending up to 200 nautical miles from the coast because this was the distance through the Exclusive Economic Zone, a distance that would be used to define the outer limits of ECA-IMO controls for these vessels[60].
>
> If these emission sources are included in the total State contribution to downwind nonattainment or maintenance and are found to be rightly excluded from the state's annual emission totals for 2005, 2012 or 2014, ***EPA may have overestimated Louisiana's contribution to downwind state nonattainment by tens of thousands of tons.***
>
> (Emphasis added.) The "Figure 7" referred to in this Alpine Geophysics review is reproduced below and dramatically depicts the potential overestimated emissions:



[60] Exhibit 11, at p12, citing http://www.epa.gov/airquality/transport/pdfs/2005_emissions_tsd_07jul2010.pdf.

As Louisiana is not responsible for offshore CMV shipping beyond its legal boundary, emissions from sources beyond that boundary should not be counted as part of Louisiana's emissions inventory and should not be included in the projected contributions to nonattainment or interference with attainment *from Louisiana* to a downwind state. Those emissions should be within federal control, and if reductions are needed from those vessels, such should be a federal matter. LCA requests that EPA remove any C3 marine vessel emissions from both the NOx and SO2 and other applicable pollutant emission inventories for Louisiana to the extent that they are attributable to port or underway emissions not within Louisiana's geographic boundary.[61]

Finally, it appears that EPA overestimated the C3 CMV emissions, both those within the Louisiana geographic jurisdiction, and outside of Louisiana by failing to reduce those emission estimates in accordance with new federal rules regulating such. The EPA Preamble to the proposed Transport Rule/FIP stated:

> Nonroad mobile emissions were created only with NMIM using a consistent approach as was used for 2005, but emissions were calculated using NMIM future-year equipment population estimates and control programs for 2012 and 2014. Emissions from 2012 and 2015 were used for locomotives and category 1 and 2 (C1 and C2) commercial marine vessels, based on emissions published in OTAQ's Locomotive Marine Rule, Regulatory Impact Assessment, Chapter 3. For category 3 (C3) commercial marine vessels, a coordination strategy of emissions reductions is ongoing that includes NOx, VOC, and CO reductions for new C3 engines as early as 2011 and fuel sulfur limits that could go into effect as early as 2012. However, given the uncertainty about the timing for parts of these emissions reductions and the fact that the 2012 modeling was conducted well in advance of the December 2009 publication of the rule, we have not used the controlled emissions in modeling supporting this proposal.[62]

In short, not only did EPA erroneously include C3 CMV emissions of SO2, NOx and other constituents from vessels hundreds of miles offshore as being part of Louisiana's significance budget, EPA also overestimated all of the C3 CMV emissions on and off-shore because the full impact of the December 2009 rule was not included in the estimates. LCA requests that EPA reevaluate the C3 CMV emissions to delete those that are not within Louisiana jurisdiction and also to take into account an appropriate projected control factor from the 2009 rule.

b. Point Source Emissions

The EPA estimate of 2005 point source emissions of NOx and SO2 compared to the values in LDEQ's Certified Emissions Inventory for 2005 are shown below:

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[61] *Id.*

[62] See 75 Fed. Reg. at 45,244.

	NOx tpy	SO2 tpy
EPA 2005 TR Inventory	228,953	275,588
LDEQ 2005 Certified Inventory[63]	222,651	272,974
Overestimate by EPA	+6,302	+2,614

LCA requests that EPA revise the 2005 emissions inventory used for the Transport Rule to reflect the values certified by Louisiana DEQ from its annual emissions inventory. The LDEQ reviews and certifies this data per EPA rules and guidance each year. The EPA 2005 inventory was based partially on estimates and assumptions by EPA and is of inferior quality to the Louisiana data. Given that even a small overestimate by EPA could adversely affect the projections as to whether Louisiana emissions may interfere with Harris County's ability to maintain attainment with the annual PM2.5 NAAQS, the LDEQ value should be used.

c. Motor Vehicle Emissions

EPA's 2005 estimate for motor vehicle NOx emissions was more than 16,000 tpy greater than the 2005/2006 value LDEQ used in the supporting documentation and modeling for its SIP redesignation to ozone attainment as shown below:

	NOx tpy On-road
EPA 2005 TR Inventory	112,889
LDEQ	96,728
Overestimate by EPA	+16,161

LDEQ's consultant used NMIM and Mobile6 v.6.2 modeling. The input for the models for the 5-parish Baton Rouge area are described on pages 208-217 of the Technical Support Document for LDEQ's SIP revision submitted to EPA in support of redesignation of the Baton Rouge Area to 1997 8-hour ozone NAAQS attainment.[64] That document also indicates the NMIM version NCD20060725, provided by EPA, was used to develop the on-road inventory for areas outside the 5-parish Baton Rouge area.[65]

EPA apparently used a draft version of MOVES to estimate on-road emissions. For the reasons stated by the Louisiana Department of Environmental Quality ("LDEQ") in its

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[63] Louisiana Department of Environmental Quality, Criteria Pollutant Data Sets, 2005 Certified Totals of Criteria Pollutants for Louisiana, http://www.deq.louisiana.gov/portal/default.aspx?tabid=1758.

[64] LDEQ 8HR SIP TSD at pp. 208-217.

[65] *Id.*

comments in this docket, LCA believes that the state inventory is more accurate than that used by EPA for this rulemaking as it reflects state-specific information based upon knowledge of the LDEQ rather than assumptions. LCA requests that EPA revise its 2005 emission inventory for this TR/FIP rulemaking to use the LDEQ values and then remodel. LCA is confident that the revised values will not show any interference with maintenance at the Clinton Drive monitor in Harris Co., Texas.

d. Emissions Inventory - General

In addition to these comments, LCA incorporates the comments of Alpine Geophysics noted on Exhibit 11.

3. EPA Failed to Include Enforceable Reductions in the Modeling Used to Project Future Impact

a. Failure to Include Consent Decrees

LCA believes that EPA has failed to include a number of federally enforceable New Source Review ("NSR") and other federally enforceable consent decrees for non-EGUs in its IPM modeling efforts. This omission resulted in EPA greatly overestimating both SO_2 and NOx emissions from Louisiana and from Texas. Because EPA proposes to include Louisiana in the TR/FIP based solely on EPA's modeled projection that Louisiana will contribute only 0.34 ug/m^3 PM2.5 in calendar year 2012 at one monitor in Harris County, Texas, LCA believes that EPA should reevaluate Louisiana's inclusion in the Transport Rule and perform new modeling with these excess emission projections appropriately reduced.

In the preamble to the proposed Transport Rule, EPA notes that to quantify the impact of the states' emissions on downwind NAAQS attainment and maintenance sites, the Agency had to analyze the emissions from the states and "take…into account emissions reductions."[66] Using air quality modeling, EPA determined that Louisiana's SO_2 emissions from EGUs in 2005 were 109,851 tpy.[67] EPA estimates that, without the Transport Rule or the Clean Air Interstate Rule ("CAIR"),[68] Louisiana's SO_2 emissions from EGUs will be 100,239 tpy in 2012.[69] EPA then projects that, with the Transport Rule, Louisiana's EGU SO_2 emissions would total 93,169 tpy (without variability allowance) in 2012 with EPA's preferred option of limited interstate trading.[70] Assuming that the IPM v.3.02 projection for 2012 TR SB Limited Trading is correct, EPA estimates that the SO_2 emissions reduction that would be garnered by implementing the

[66] *See* 75 Fed. Reg. 45,210, 45,233 (Aug. 2, 2010).

[67] *Id.* at 45,240 tbl.IV-C-1.

[68] EPA has labeled these emissions as "Base Case" emissions. *Id.* at 45,217 n.6.

[69] *Id.* at 45,241 tbl.IV-C-3.

[70] Environmental Protection Agency, IPM Parsed Files and Run Files, TR SB Limited Trading (Parsed File), (total SO2 from all Louisiana EGUs included by EPA), available at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html.