BEFORE THE ADMINISTRATOR OF
THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

October 7, 2011

In Re: Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals; Final Rule
76 Fed. Reg. 48,208

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

PETITION FOR RECONSIDERATION AND STAY BY
SOUTHERN COMPANY SERVICES, INC.

Pursuant to Section 307(d)(7)(B) of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B), Southern Company Services, Inc., on behalf of Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power, respectfully petitions the Administrator of the Environmental Protection Agency ("Administrator," "EPA," or "Agency") to reconsider the final Cross-State Air Pollution Rule ("CSAPR," "final rule" or "rule") and requests that the Administrator stay the effectiveness of the final rule pending reconsideration and judicial review.

Southern Company is a leading U.S. producer of electricity – generating and delivering electricity to over four million customers in the southeastern United States. As the Southeast's premier super-regional energy company, Southern Company's challenge and responsibility are to provide reliable and affordable energy for the people across our region. In doing so, the health of our employees, customers and the public and the protection of our natural environment are among our highest priorities. Since 1990, we have reduced emissions of sulfur dioxide ("SO2") and nitrogen oxides ("NOx") by over 70%, while electricity generation has increased about 40% to serve growing demand. Through 2010, Southern Company has invested approximately $8.1 billion in environmental controls. This investment includes the installation and operation of scrubbers at 24 of our coal units, SCRs at 16 of our coal units and baghouses at four of our largest coal units. Plans are in place to spend at least an additional $1.2 billion through 2013 to further reduce emissions of NOx, SO2 and mercury. Southern Company is committed to doing its part in making sure the Southeast continues to be a great and environmentally healthy place to live, now and for future generations.

On August 2, 2010, two years after the vacatur of the Clean Air Interstate Rule ("CAIR"), EPA issued the proposed Transport Rule – an extraordinarily complex rule to address significant contribution to downwind non-attainment areas of ozone and PM2.5. The pre-publication proposal topped 1,300 pages and was accompanied by thousands of pages of technical support documents and other supporting materials. And, unlike prior interstate transport rules (the NOx SIP Call and CAIR), this proposal was developed almost entirely behind closed doors, so that the proposal was the first opportunity to review and understand EPA's approach, methodology, and rationale for its rule.

Southern Company submitted detailed comments on EPA's proposed rule and the subsequent Notices of Data Availability ("NODA"). In those comments, Southern Company consistently expressed its significant concerns about the process, the methodology, the assumptions and inputs and the timeline. EPA's final rule confirms those concerns.

This rule is broken. Numerous petitions for reconsideration have been filed over the past several weeks because the final rule results in substantial, surprise reductions in statewide emissions budgets as compared to the proposal and the assumptions and data that form the foundation of those budgets are riddled with errors. EPA has recently acknowledged numerous errors and has initiated a process to correct them and revise the budgets. The Company will participate in that process, but believes that a stay of the rule and a broader reconsideration rulemaking are required.

Three Southern Company states – Florida, Georgia, and Mississippi – are among the states severely impacted by unexpected significant reductions in state emissions budgets. The annual SO2 emissions budget for Georgia in 2012 dropped by almost a third as compared to the proposed rule. Georgia's 2014 annual NOx budget dropped by over 45% and its 2014 ozone season NOx budget dropped by 43% compared to the proposal. Similarly, the final 2012 and 2014 ozone season NOx budgets for Florida and Mississippi dropped by 46% and 34% respectively as compared to the proposed rule.

This rule is broken in part because it relies too heavily on EPA's use of the proprietary Integrated Planning Model ("IPM") to establish the future emissions budgets at the heart of the rule. IPM, in turn, depends on hundreds of thousands of inputs and assumptions – from future electricity demand and projected fuel prices to unit-specific characteristics and operational limitations. With the proposed rule, EPA provided a description of the models it intended to use, including details on some but not all of the assumptions, inputs, and outputs. EPA also described the method proposed to develop the state emissions budgets based only in part on the IPM. But just a few weeks before the comment period on the initial proposal closed, EPA released notice of its intent to use updated models and new inputs and assumptions that would inform the final rule. EPA later released two more NODAs making additional changes in inputs, assumptions, and methodology. Yet despite repeated requests, in its rush to publish a final rule, EPA refused to provide revised emissions budgets based on those new models and assumptions and instead required review of the new information in a vacuum, depriving the public of a meaningful opportunity to review and comment on the evolving rule. Because IPM is a proprietary model with no available surrogate, commenters were simply left to guess the impact of the new inputs and assumptions on the final budgets.

In this case, IPM is much like a kaleidoscope. While you may know the universe of colors, with each slight turn a very different and unpredictable pattern appears. Even small changes or errors in the input assumptions result in very different outcomes. Without the model itself, predicting the outcome or even replicating it is impossible. IPM is thus a very opaque and unstable base on which to build the emissions budgets that are central to this rule.

In its detailed written comments, Southern Company raised concerns about EPA's methodology and identified numerous errors in the inputs and assumptions. The Company repeatedly requested that EPA correct the errors in its data bases, address flaws in its methodologies, re-run its models and provide a complete revised proposal for public review and comment. EPA refused. Instead, EPA quickly revised assumptions, corrected some input data, changed aspects of its methodology and then issued a final rule. Not until that final rule – just five months before the initial compliance deadline – did we see the radically different state emission budgets.

The rule is broken in other ways as well. For example, EPA announces a new method for determining significant contribution and identifying cost-effective emission reductions. Then, it inconsistently applies the new method in developing many of the state budgets. In some cases EPA requires reductions well beyond those the Agency deems cost effective based on its own cost-effectiveness thresholds.

Finally, and just as troubling, EPA flouts the longstanding principle of cooperative federalism that underlies the Clean Air Act ("Act" or "CAA") by bypassing the states and mandating a federal plan instead of allowing states to develop their own implementation plans consistent with the Act and prior EPA practice. As a result, this rule sets a very bad precedent as the path forward for addressing significant contribution for future NAAQS.

The speed with which EPA insists on finalizing this rule and implementing the initial reductions is particularly perplexing when CAIR remains in place and is achieving real, tangible air quality improvements, including air quality that attains the targeted ozone and PM-2.5 air quality standards at all of the ozone and PM2.5 air quality monitors that Alabama, Florida, Georgia, and Mississippi were purportedly impacting and that brought them under the rule in the first place. The rush to implement the program in 2012 is all the more perplexing given that many of the benefits projected by EPA's "remedy case" to occur in 2014 appear to have already been achieved under CAIR.

In light of the above and additional evidence presented below, EPA should stay the implementation of CSAPR, leaving CAIR in place to provide continued improvement in air quality and take the time to get this rule right. EPA needs to rework its unstable and opaque methodology; properly engage the stakeholders and states; set reasonable compliance deadlines; and allow the states time to exercise their proper roles through the SIP process. While Southern Company and its operating companies will make every effort to minimize the cost of implementing this program, EPA's haste will result in increased costs to our customers without commensurate air quality benefits. We respectfully request that the Administrator stay the effectiveness of this rule and initiate a reconsideration rulemaking, with adequate notice and opportunity for public comment.

Southern Company also supports the petitions for reconsideration submitted by the Utility Air Regulatory Group, the Florida Electric Power Coordinating Group and the States of Alabama, Georgia, Florida, and Mississippi.

Standard of Review for Reconsideration and Stay

EPA must grant reconsideration of a final rule when the petitioner demonstrates that it was "impracticable to raise [an] objection" within the time allowed for public comment or "the grounds for such objection arose after the period for public comment (but within the time allowed for judicial review) and … the objection is of central relevance to the outcome of the rule." CAA § 307(d)(7)(B).

Authority for granting a stay derives from both the CAA, 42 U.S.C. § 7607(d)(7)(B), and the Administrative Procedure Act, 5 U.S.C. § 705. Section 307(d)(7)(B) of the CAA authorizes EPA to stay the effectiveness of a final rule for three months as justice requires if a reconsideration proceeding is convened. APA § 705 authorizes EPA to postpone the effectiveness of a rule pending judicial review when justice so requires. Under either provision, EPA has broad discretion to delay the effective date of a rule, based on the specific facts and circumstances before it. *Industrial, Commercial, and Institutional Boilers and Process Heaters and Commercial and Industrial Solid Waste Incineration Units*, 76 Fed. Reg. 28,662 (May 18, 2011).

For the reasons stated herein, EPA must grant reconsideration and stay its final rule.

I. The State Budgets for Florida, Georgia and Mississippi Are the Product of Numerous Errors and Incorrect Assumptions that Completely Undermine The Rule's Integrity.

More so than in any other interstate trading program, the final emissions budgets are the heart of EPA's final rule. The state budgets take on greater significance in this rule due to the hard caps reinforced by assurance provisions and geographic limits on emission trading. The heart of this rule, however, is in question. Unlike the proposal, in the final rule EPA chose to establish all of the state budgets based on projected emissions using the proprietary Integrated Planning Model (IPM). To make the projections, the model requires hundreds of thousands of inputs and assumptions ranging from projected energy demand, fuel prices, and allowance prices to individual unit-specific characteristics such as fuel-type, fuel constraints, current and future emission controls, applicable emission limits, etc. Given these numerous and varied inputs, the model predicts future generation and associated emissions. In every instance, the state budgets are simply the model's projection of emissions based on EPA's selected inputs and assumptions, and the budgets are only as good as the assumptions from which they are derived.

A surprising number of important inputs and assumptions used to generate the final budgets are simply wrong. Taken together, these incorrect assumptions and inputs would have a significant impact on the final budgets and thus are of central relevance to this rulemaking. Some of the errors were identified by Southern Company in its previous written comments on the proposed rule and NODAs but have not been corrected by EPA in the final rule. Some of the errors may have been introduced through EPA's various proposals but the significance or extent of the error was not readily apparent based on the context and proposal at the time, making it impractical to comment given the number of data points and time constraints.[1] Other errors are entirely new to the final rule.[2] These errors fall into

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1 Southern Company has commented extensively throughout this rulemaking on EPA's inputs and assumptions, among other things. However, given the sheer number of data points, the various alternatives introduced in the proposed rule, and the new inputs, assumptions, and models introduced in subsequent notices, and the limited time for public review and comment, it has been impracticable to comment on every input and assumption that might possibly be relevant to the final rule. Furthermore, IPM is a proprietary model, and no surrogate exists to approximate IPM results. Therefore, in the absence of IPM runs provided by EPA to illustrate the relative impact of new model versions, updated emission inventories, fuel prices, demand curves, etc., the public, including industry, was forced to comment on these new tools, inputs, and assumptions in a vacuum, without being able to test and prioritize their significance.

2 A number of these errors were raised on a September 28, 2011 conference call with the Agency. We followed up that call, with a summary list of "technical corrections," sent by email on September 29, 2011, to the Agency. Since we are left to guess what EPA considers a "technical correction" and what requires broader reconsideration by the Agency, we

two categories – incorrect base case assumptions and incorrect remedy case assumptions.

A. The State Budgets Are Based on Significant Errors in EPA's *Base Case* Assumptions.

Many assumptions and errors in the base case model runs (i.e., 2012 and 2014 without CAIR or CSAPR) dramatically reduce the Agency's starting point for making emission reductions and thereby directly reduce the state budgets. Most of these errors are not new. Southern Company commented previously on the errors listed below, which impacted the base case projections. Specifically, Southern commented on: (i) errors in pollution control installation dates; (ii) premature unit retirements; (iii) an erroneous biomass fuel switch assumption; and (iv) an assumed substantial drop in projected fossil fuel generation and fossil fuel heat input. EPA neither fixed these errors nor responded to these comments.

1. Errors in Pollution Control Installation Dates.

The final rule incorrectly assumes that Georgia Power's Plant Branch Units 1, 2, & 4, Plant Yates Units 6 & 7, and Plant Scherer Unit 1 will have installed and begun operating SCRs and FGDs by January 1, 2014. These controls are required by Georgia's Multi-Pollutant Rule, discussed in more detail below. This state rule requires installation of SCRs and FGDs on the state's largest 23 coal-fired EGUs by dates specified in the rule and, in virtually every case, requires those controls to be operated year round once installed. While the Multi-Pollutant Rule requires SCRs and FGDs at each of the units referenced at Plants Branch, Yates and Scherer, the compliance dates are well after the January 1, 2014 date assumed in EPA's modeling. Southern Company provided a copy of the Georgia Multi-Pollutant Rule along with its comments on the initial proposal. Because EPA wrongly assumed these controls would be in place and operating in January 2014, the emission reductions associated with the controls are captured in the IPM base case runs and reduce Georgia's base case SO2 and NOx emissions by tens of thousands of tons.[3] The result is even lower remedy case emissions budgets because, as noted above,

include items from our list of technical corrections here and incorporate that email and list herein (Attachment A).

3 The SO2 and NOx emissions in the 2012 remedy case, where these units are correctly modeled without SCR and FGD, shows how the units may be expected to model in the 2014 remedy case if the errors in the control installation dates are corrected. This assessment shows over 40,000 tons of SO2, over 14,000 tons of annual NOx, and nearly 6,000 tons of seasonal NOx were incorrectly cut from Georgia's 2014 budgets due to these control installation date errors alone. The SO2 tons incorrectly cut from the state budget would likely be even larger because the 2012 remedy emissions estimates are already underestimated due to separate errors in fuel switch assumptions for Georgia Power's Plants Branch and Yates in 2012 (discussed below).

the base case is the foundation for the remedy case. Southern Company brought these errors to the Agency's attention,[4] but they were not corrected.

In the proposed Transport Rule, EPA incorrectly assumed that Gulf Power's Plant Crist Unit 6 would not have an SCR in the base case for 2012 or 2014. Due to Southern's comments that an SCR would startup in 2012, EPA added the SCR. However, EPA assumes that Plant Crist Unit 6's SCR is "Dispatchable", when in fact the unit will be operated year-round.[5]

2. Premature Unit Retirement.

The final rule incorrectly assumes that Georgia Power's Plant McDonough Unit 1 will be retired as of January 1, 2012. This unit will not be retired until April 30, 2012. Had EPA corrected this error, the model (and therefore Georgia's 2012 budget) would have reflected anticipated emissions from this uncontrolled unit. Southern Company brought this error to the Agency's attention in previous comments,[6] but it was not corrected.

3. Incorrect Biomass Conversion.

The final rule incorrectly assumes that Georgia Power's Plant Mitchell Unit 3 is converted from coal to biomass on January 1, 2012, and that unit's emissions appear to be excluded from the state budget. This unit is not scheduled to be converted to biomass at this point, in large part due to uncertainty surrounding EPA's Industrial Boiler MACT. With the continuing uncertainty around the Industrial Boiler MACT and other rules, the conversion is not expected to occur before late 2015. Thus, this unit's emissions – as an uncontrolled coal unit – should have been captured in all the modeling runs (base and policy) for 2012 and 2014. Even if the unit were converted on a timeframe relevant to EPA's analysis, it would still have emissions that should be included in the state budget because it would be a covered unit. Southern Company brought this error to the Agency's attention,[7] but it was not corrected.

4. Incorrect Fuel Switches.

The final rule incorrectly assumes in the base case that Georgia Power's Plant Yates Unit 6 & 7 and Plant McIntosh Unit 1 burn coal with an SO2 emission rate of less than 1 lb/mmBtu. In 2010, the average SO2 emission rates from the Plant Yates

[4] Southern Company, Proposed Transport Rule Comments at 25 and Attachment B (Oct. 1, 2010).

[5] *See* Gulf Power Plant Crist Title V Permit (Permit No. 0330045-031-AV); Gulf Power Plant Crist 6 SCR Air Construction Permit (Permit No. 0330045-028-AC).

[6] Southern Company, Proposed Transport Rule Comments at Attachment B (Oct. 1, 2010).

[7] Southern Company, NODA-1 Comments at 18 (Oct. 15, 2010).

units were more than twice as high. McIntosh Unit 1's actual emission rate is nearly double EPA's assumed base case emission rate for the unit. EPA has apparently incorrectly identified these three units as NSPS Subpart D units. None of these units are subject to NSPS Subpart D. By making this incorrect assumption to "switch" the fuel for these units in the base case, EPA is able to models nearly 30,000 tons of SO2 reductions at no cost to Georgia Power – assuming EPA's modeled base case heat input. As discussed later, fuel switching to coal with a sulfur content of less than 1 lb/mmBtu would cost well over EPA's $500/ton threshold. Southern Company brought this error to the Agency's attention,[8] but it was not corrected.

			SO2 Emission Rates lb/mmBtu			
Plant Name	Plant ID	Unit ID	2010 Actual	EPA Assumed 2012 Base Rate	EPA Assumed 2012 Remedy Rate, including biomass co-firing	EPA Assumed 2012 Remedy Rate, coal only
Units assumed to fuel switch in 2012 base case at no cost						
McIntosh	6124	1	1.71	0.95	0.86	0.96
Yates	728	Y6BR	1.94	0.94	0.91	0.95
Yates	728	Y7BR	1.92	0.94	0.91	0.95

5. Substantial Changes in Generation and Heat Input.

The final budgets are based on significant unexplained reductions in generation and heat input, particularly in Georgia, Mississippi and Florida between the proposed and final rule. Ozone season heat input in the 2012 base case for the CSAPR-affected units shows a decrease in Georgia, Mississippi and Florida compared to 2010 actual heat inputs. Although Alabama's total generation is projected to slightly increase approximately 5%, the other states drop dramatically, as much as 39% in Mississippi. The projected reductions are inconsistent with historical data and are unusual even in absolute terms.

In its comments on EPA's first NODA, Southern Company commented that projected coal generation decreased significantly in the base case as a result of new modeling assumptions.[9] By way of example, Southern Company noted that Georgia's annual base case and remedy case heat input decreased by 20% from the proposed rule (and 2010 actual levels). To date, EPA has not explained or documented the reasons for such dramatic departures from reality.

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8 Southern Company, Proposed Transport Rule Comments at Attachment B (Oct. 1, 2010).

9 Note, Southern Company and other stakeholders did not have an opportunity to comment on the generation or heat input changes in the 2012 remedy case. EPA did not provide this information; EPA only made the 2012 base case available for comment.

These substantial changes in generation and heat input diverge significantly from actual historical levels which have increased year-over-year, every year in recent memory, except during the great recession.[10] With the exception of 2008 and 2009, consistent increases in generation and heat input have been typical given that the Southeast has long been one of the fastest growing regions in the country. Even during the depths of the recession, Southern Company generation decreased less than 4%.[11]

These erroneous reductions in projected heat input cut the state budgets and resulting allowance allocations making state-by-state compliance exceedingly difficult. While Southern raised the issue in its comments, no response has been provided. The following discussion provides state-specific examples of these erroneous projections.

a) Georgia

In the final rule, EPA assumes that generation from CSAPR-affected units in Georgia will drop by 16% in 2012 as compared to 2010 actual and nearly 10% in 2012 as compared to 2009, which was the deepest valley of the great recession. By contrast, in the proposed rule, IPM's generation projections for the CSAPR-affected units were closer to historical values. Therefore, we had no reason to comment on fossil generation projections in the initial proposal, which included the proposed budgets. The reduction appeared in the first NODA, and, despite significant time constraints and an overwhelming number of new assumptions and data points, we

[10] The following table documents actual total megawatt hours generated from 2001 to 2010 and demonstrates that generation increases each year except during 2008 and 2009.

	Total Retail Weather Normalized Sales (MWh)				
Year	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Gulf Power
2001	147,178,298	49,726,504	77,773,189	9,381,403	120,297,202
2002	150,822,003	51,401,086	79,403,651	9,386,891	10,630,375
2003	153,023,696	52,608,612	80,187,894	9,330,238	10,896,951
2004	157,475,653	54,400,730	82,573,574	9,532,151	10,969,198
2005	159,072,720	55,616,079	83,409,049	8,774,952	11,272,640
2006	160,852,045	55,913,876	84,628,745	8,915,836	11,393,589
2007	161,797,826	55,520,701	85,483,480	9,337,302	11,456,343
2008	160,372,146	55,330,211	84,446,624	9,218,198	11,377,114
2009	153,199,985	51,340,627	81,706,157	9,295,584	10,857,617
2010	156,262,312	53,136,844	82,940,666	9,364,451	10,820,351

[11] *See* Table, Infra Note 10 (showing Southern Company decrease in megawatt hours from 2008 to 2009).

commented on this significant reduction,[12] but EPA did not directly respond to the comment.

This error dramatically reduces Georgia's SO2 and NOx emissions budgets and the resulting allowance allocations. With the benefit of time and additional information, we now see that EPA also assumed a 12% drop in overall generation in Georgia beginning in 2012 over 2010 actual and a 17% drop from the proposed rule. Oddly, apparently to make up for some of the reduced fossil generation, IPM projects a nearly 70% increase in hydroelectric power in 2012 over 2010 actual. In fact, this level of hydropower is greater than any reported level of hydroelectric generation for Georgia in EIA.[13] Clearly, these types of assumptions call into question the IPM results. EPA provides no explanation for why these projections differ so significantly from past actual levels, nor any justification for relying on such projections, which are so obviously unusual. This is an extraordinarily important error to correct given the direct impact on the state emission budgets.

b) Mississippi

Similar to the reduction in generation in Georgia, in the final rule, EPA projects a 46% reduction in 2012 ozone season base case heat input in Mississippi for the CSAPR affected units as compared to 2010, resulting in a 46% reduction in base case generation in Mississippi during peak season. It appears that in the final base case runs, IPM eliminated 94 TBtu of heat input from Mississippi's 2010 heat input inventory by assuming that certain units simply would not run beginning in 2012 (before any controls are required). As explained in detail in the Petition for Reconsideration and Stay filed by the Mississippi Public Service Commission, this base case assumption or projection bears no relationship to reality and thus requires explanation. As in Georgia, the impact is significant – it results in a substantially reduced ozone season NOx budget for Mississippi in 2012 that is 37% lower than 2010 actual emissions.

c) Florida

The IPM base cases for 2012 and 2014 substantially underestimate the projected ozone season / peak season heat input for Florida and Gulf Power. The total Florida ozone season heat input for CSAPR affected-units drops by 13% over 2010 levels. Southern Company had no reason to comment on this during the proposed rule because the ozone season heat input in the proposed rule was very near historical levels. As shown in the following table, when compared to Gulf Power's actual heat input for CSAPR-affected units in 2010, EPA projects a 31% decrease in 2012. IPM's assumed reduction in generation has no air quality basis

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[12] Southern Company, NODA-1 Comments at 18 (Oct. 15, 2010).

[13] The EIA database contains reported data from 1990 to 2010.

given that the reduction occurs in the base case. This error is of central relevance to Florida's ozone season budget and is not a logical outgrowth of the proposed rule.

Based on Gulf Power's territorial load demand presented in the 2011 Ten Year Site Plan submitted to the Florida Public Service Commission, Gulf Power would need to import approximately 2,748 GWHs of power during the 2012 summer months to meet demand while achieving compliance with CSAPR. Purchasing allowances to cover the shortfall is not a viable option because of Florida's severe under-allocation and the restrictions on interstate trading.

Plant Name	Historical Heat Input 2010	EPA Base 2012 Heat Input	Delta mmBtu from 2010 Actual to EPA Base 2012	% Change mmBtu 2010 Actual to 2012 Base Proposed
Crist	30,757,508	24,851,012	(5,906,496)	-19%
Lansing Smith	19,976,850	8,856,540	(11,120,310)	-56%
Scholz	746,746	1,559,484	812,738	109%
Gulf Average Total	51,481,105	35,267,006	(16,214,099)	-31%

EPA must reconsider these projections in light of historical trends and other projections. If the Agency decides to continue to rely on these extraordinary assumptions, it must document the reasons for that decision.

B. The Budgets Are Also Based on Significant Errors in the Remedy Case.

1. EPA Failed to Apply Its Stated Method to Accommodate Short Term Restrictions on Coal Switching at Southern Company Units.

In the proposed rule, EPA explained generally that it assumed sources could switch coal by 2012 to comply with the rule's SO2 restrictions. Southern Company commented at length about the infeasibility of switching to lower sulfur coals and outlined numerous reasons switching would be costly and impractical at its coal units.[14] Those comments explained, among other things, that as of October 2010 two-thirds of Southern Company's required coal supply for 2012 was under contract and that this commitment level would increase by the time of the final rule. The comments also outlined contractual barriers to switching coals. EPA did not respond to or accommodate those comments.

14 Southern Company, Comments on Propose Transport Rule at 21 (Oct. 1, 2010).

In the final rule, EPA explains that it received numerous comments about the cost and schedule impacts of coal switching in 2012. EPA explains that it agreed with the concerns of many commenters, specifically citing as an example limitations in "existing coal supply contracts."[15] In a technical support document, EPA explains that it accommodated short term fuel switching limitations where commenters "identified by name a group of units (e.g., *by company* or by plant name) whose coal choices could not change over the short run."[16] Given that stated process, it was a mistake for EPA to not restrict coal switching at Southern Company units for 2012.

Should EPA believe that Southern Company's comments were not specific enough to trigger the Agency's accommodations, the Company urges EPA to reconsider that unsupportable position. EPA provided only sixty days for public comment on its voluminous, complex, proposed rule and began issuing new data, models, and assumptions before the close of the first comment period. In the limited time allotted, the Company prioritized its comments and provided the greatest detail on issues in the proposal that impacted the operating companies and their customers. Fuel switching was not one of those issues – for good reason. First, in the proposed rule, the budget at issue – Georgia's – was based on adjusted 2009 historical emissions as opposed to projected emissions using IPM. In the IPM projections provided, it did not appear that any significant fuel switching had been assumed. To the contrary, it simply appeared that EPA had made numerous errors in fuel assumptions for many units, and those errors were specifically addressed in the comments. In fact, it appears that remedy case fuel switching was only assumed at one plant in Georgia. Thus, in the proposed rule, fuel switching had significantly less impact on the relevant state budgets. Therefore, given the limited time to comment, the Company did not provide an exhaustive list of all coal contracts and unit-specific limitations on fuel switching. To do so seemed unnecessary and would have been impracticable.[17]

The final rule is quite different from the proposed rule with respect to fuel switching at certain Southern Company units. In the final rule, EPA switches the Georgia Power units that do not yet have scrubbers to a very low sulfur bituminous coal. EPA also assumes in the base case that most of these units are burning a coal

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15 76 Fed. Reg. at 48,283-84.

16 EPA, Documentation Supplement for EPA Base Case v.4.10_FTransport – Updates for Final Transport Rule at 46 (June 2011) (emphasis supplied).

17 EPA requested comments on fuel switching and Southern Company provided comments on that issue. It would be unreasonable for EPA to now claim that the comments were not sufficiently detailed under the circumstances. EPA cannot possibly want or expect commenters to submit detailed unit level data that is irrelevant at the time it is submitted. Such a standard would bog down rulemaking. EPA should have provide the updated modeling requested in the Company's NODA comments. That might have provided sufficient notice of potential fuel-switching impacts, allowing the Company the opportunity to provide unit specific comments.

with a sulfur content much higher than current or recent historical levels. The combination of the high sulfur base case assumptions and the very low sulfur remedy case projections results in an SO2 emission reduction of 180,407 tons in Georgia, which has a substantial impact on the final SO2 emissions budget. The very low sulfur fuel assumptions in the remedy case alone reduce Georgia's SO2 emissions by 80,000 tons.[18] Thus unlike the proposal, in the final rule fuel switch has a substantial impact on Georgia's budget. For the reasons stated below, these coal switches are impossible.

In short, Southern Company commented specifically on very real short term restrictions on coal switching – albeit not to the unit level. Yet EPA failed to apply its stated accommodation. Furthermore, commenting on unit-level contract commitments would have been challenging because coal for Georgia Power is not procured on an individual unit basis; rather it is procured for the group of several plants on a common transportation corridor (e.g., CSX or Norfolk Southern), with additional consideration of plant operational constraints. The Company had little reason to comment more specifically, because only a few of its plants showed an indication of fuel switching in the proposal and the 2012 budget was based on historical data and not modeled emissions. In the final rule, however, fuel switching plays a central role in the 2012 budget. This change is not a logical outgrowth of the proposal. EPA must take into account more detailed information on fuel switching for these units on reconsideration.

2. EPA's New Fuel Switching Assumptions for Southern Company Units Are Deeply Flawed and Have No Basis in Reality.

In addition to the contract limitations noted in Southern Company comments on the proposed rule, there are a number of other reasons Georgia Power's fourteen unscrubbed units will not and cannot switch to the very low sulfur bituminous coal that EPA assumes.[19]

First, as outlined in the attached report by Energy Ventures Analysis, Inc. ("EVA") (Attachment B), even if a coal switch of this magnitude could otherwise occur within EPA's short timeframe – which it cannot– there is simply not enough of the assumed coal available in 2012 and 2013. These fourteen units are projected to switch to an Alabama bituminous coal with an emission rate of 0.95 lbs/mmBtu. As

[18] The 80,000 tons are the difference between EPA's current 2012 remedy case versus a 2012 remedy case that uses *current* SO2 emission rates instead of very low sulfur rates.

[19] As we explained in our comments on the proposed rule, the percentage of our 2012 coal need that is under contract increased from the time of the proposed to final rule. At the time of the final rule, the fourteen units that EPA switches to very low sulfur bituminous coal had purchased approximately 80% of their coal need. Because of projected reduced dispatch of these units due to the CSAPR, coal for these units is now fully committed.

EVA explains, Alabama bituminous coal with "low-sulfur" emission rates of 0.95 pounds SO2 per million Btu is not available for Georgia Power to purchase to reduce emissions to this level.

According to the Energy Information Administration, 18.8 million tons of coal were produced in Alabama in 2009. This total includes all qualities (metallurgical and steam) and all grades of sulfur content. Nine million tons were exported to world markets or used domestically for metallurgical coal, and an additional 1.2 million tons was sold domestically to industrial markets. Only 8.3 million tons was supplied for domestic power production. Based on EPA's model, Georgia Power's units alone would need about 6.6 million tons (or 165 trillion Btu) to comply with the rule. Additionally, most – if not all – of the high quality, high value coal is likely committed to other customers for 2012.

Second, this coal is not available at the prices EPA assumes. EPA's IPM assumes that this coal is available at prices below $54 per ton FOB mine (2007$). In fact, because this coal is well suited for the metallurgical coal market, it is currently being exported at prices over $230 per ton FOB mine. EPA's assumption that such a large quantity of this coal is available to Georgia units at mine prices under $60 per ton is totally illogical and unrealistic.

Third, even if this coal were available in the time frame and quantities and at the price EPA assumes, these fourteen units would not be able to switch to that coal for less than $500/ton SO2. In order to model these coal switches as being cost effective (i.e., less than $500/ton SO2) IPM had to (i) incorrectly assume the coal is available at around 25% of actual market price (not including transportation) and (ii) artificially inflate the number of tons that would be removed (i.e., the denominator in EPA's cost effectiveness threshold). That is exactly what happened. As noted above, for eleven of these units, EPA has significantly overestimated the coal-sulfur content that these units burn in the base case by assuming emission rates far greater than historical rates. Specifically, in the base case EPA assumes a 4.28 lbs/mmBtu SO2 emission rate for each of these eleven units, which equates to a coal sulfur content of over 2.5%. Georgia Power has not burned coal with this type of sulfur content in almost twenty years except in *de minimis* quantities. Then, in the remedy case, the emission rate drops to 0.95 lbs/mmBtu because EPA switches all eleven units to this very low sulfur bituminous coal, on the order of 0.55 to 0.6% sulfur. EPA's base case assumptions, therefore, essentially trick the model into the fuel switch. The following tables show how this approach inflates the number of tons reduced and thus deflates the cost/ton threshold that triggers the switch in IPM.

Plant Name	Plant ID	Unit ID	SO2 Emission Rates lb/mmBtu 2010 Actual	EPA Assumed 2012 Base Rate	EPA Assumed 2012 Remedy Rate, including biomass co-firing	EPA Assumed 2012 Remedy Rate, coal only
Units assumed to fuel switch in 2012 CSAPR remedy						
Harllee Branch	709	1	1.76	4.28	0.92	0.95
Harllee Branch	709	2	1.81	4.28	0.92	0.95
Harllee Branch	709	3	1.80	4.28	0.92	0.95
Harllee Branch	709	4	1.79	4.28	0.92	0.95
Kraft	733	1	1.54	4.28	0.86	0.96
Kraft	733	2	1.56	4.28	0.86	0.96
Kraft	733	3	1.59	4.28	0.86	0.96
Yates	728	Y2BR	2.11	4.28	0.91	0.95
Yates	728	Y3BR	2.08	4.28	0.91	0.95
Yates	728	Y4BR	2.00	4.28	0.91	0.95
Yates	728	Y5BR	2.07	4.28	0.91	0.95
Units assumed to fuel switch in 2012 base case at no cost						
McIntosh	6124	1	1.71	0.95	0.86	0.96
Yates	728	Y6BR	1.94	0.94	0.91	0.95
Yates	728	Y7BR	1.92	0.94	0.91	0.95

This table shows the 2010 historical SO2 emission rate compared to EPA's 2012 base and remedy emission rates. EPA's base emission rates are more than twice the 2010 rate, which is representative of current coal. This means that the actual reduction that would be realized if these units switched to 0.95 lb/mmBtu SO2 coal is dramatically less than EPA assumes.

Plant Name	Plant ID	Unit ID	EPA Assumed Tons SO2 Reduction in 2012 Due to CSAPR	Tons SO2 Reduction Using 2010 SO2 Emission Rate In Lieu of 2012 Base Rate	Approximate Incremental Cost to Fuel Switch Assuming $500/ton SO2 Reduction and EPA's Assumed SO2 Reduction	Assumed $/ton SO2 Removed Using EPA Base SO2 Rate	$/ton SO2 Removed Using Approximate Incremental Cost to Fuel Switch Over the SO2 Removed from 2010 Actual SO2 Rate
Harllee Branch	709	1	20,748	7,271	$10,374,149	$500	$1,427
Harllee Branch	709	2	25,228	9,352	$12,614,186	$500	$1,349
Harllee Branch	709	3	39,386	14,447	$19,692,751	$500	$1,363
Harllee Branch	709	4	39,781	14,357	$19,890,538	$500	$1,385
Kraft	733	1	3,068	851	$1,534,087	$500	$1,803
Kraft	733	2	3,530	1,029	$1,764,803	$500	$1,716

Plant Name	Plant ID	Unit ID	EPA Assumed Tons SO2 Reduction in 2012 Due to CSAPR	Tons SO2 Reduction Using 2010 SO2 Emission Rate In Lieu of 2012 Base Rate	Approximate Incremental Cost to Fuel Switch Assuming $500/ton SO2 Reduction and EPA's Assumed SO2 Reduction	Assumed $/ton SO2 Removed Using EPA Base SO2 Rate	$/ton SO2 Removed Using Approximate Incremental Cost to Fuel Switch Over the SO2 Removed from 2010 Actual SO2 Rate
Kraft	733	3	6,975	2,114	$3,487,468	$500	$1,650
Yates	728	Y2BR	7,642	3,740	$3,820,800	$500	$1,022
Yates	728	Y3BR	8,156	3,896	$4,078,077	$500	$1,047
Yates	728	Y4BR	10,999	4,939	$5,499,642	$500	$1,113
Yates	728	Y5BR	11,145	5,300	$5,572,639	$500	$1,052
Total			176,658	67,295	$88,329,141	$500	$1,313

This table shows that while EPA assumes 176,658 tons of SO2 reductions will occur at these units – due to coal switching primarily – the reduction that would occur if EPA modeled a realistic 2012 base SO2 rate would only be 38% of that.

None of these fuel switches would have occurred if EPA had not inflated the unit's emissions in the base case by switching them to this high sulfur coal.

Finally, the units at Plant Branch and Yates Units 2, 3, 4, & 5 cannot burn this particular coal-type without opacity issues. These units must consider the impacts on ESP performance when the fuel sulfur content drops below about 1%. As sulfur content decreases, ash resistivity increases, and the ash becomes more difficult to capture in the ESP. The ESPs for these units are not designed to perform at these very low sulfur levels. While installation of flue gas conditioning can improve ESP performance for units burning very low sulfur coals, these projects typically require at least 18 months to implement. These systems must be custom-designed for each unit. Thus, the process would include writing specifications, going through the bid process, fabrication, delivery, and on-site installation. This cannot be accomplished by January 1, 2012 and these systems cost millions of dollars. Additionally, for some units, installation of flue gas conditioning may not be enough to maintain ESP performance with very low fuel sulfur content. For example, Yates Units 2, 3, 4, & 5 already operate dual flue gas conditioning to improve ESP performance. However, even when the flue gas conditioning is in service, the ESP performance declines if coal sulfur is less than 0.9%. In those cases where ESP work would also be required to handle the very low sulfur coal, the implementation time and cost impact would likely be even greater.

In sum, these modeled coal switches for Georgia are an absurd projection and they undermine the credibility of the IPM. Georgia Power will not and cannot switch 6.6 million tons of coal purchases for 2012 to very low sulfur bituminous coal, and it certainly cannot do so for less than $500/ton SO_2 removal. In fact, the

Company estimates that if it were even possible to undertake switching coals for 2012 and 2013 to the grades projected by IPM for Georgia Power's wholly owned plants, the incremental direct fuel cost increase could be between $650 million and $1.5 billion dollars—over these two years. Given the magnitude of the impact of EPA's projected fuel switches on Georgia's emissions budget and the introduction of significant fuel switching for the first time in the final rule, EPA must reconsider these assumptions and projections.

3. Incorrect NOx Emission Rates and Control Assumptions

Gulf Power Company's operations are heavily penalized by the proposed NOx emission rates in the remedy case runs for 2012 and 2014. As shown in the following table, EPA has assumed unrealistic NOx emission rates for Gulf Power's Plant Crist Units 4 & 5 and Plant Smith Unit 1, all of which have SNCR, and for Plant Scholz Units 1 & 2.

Plant	Unique ID/Boiler ID/ORIS ID	EPA's Controlled NOx Policy Rate (lb/mmBtu)	Corrected Actual Controlled NOx Rate (lb/MMBtu)
Crist Electric	4	0.180	0.402
Crist Electric	5	0.180	0.364
Lansing Smith	1	0.180	0.286
Scholz Electric	1	0.245	0.570
Scholz Electric	2	0.334	0.570

EPA also grossly underestimated the overall emission rates and tons for Gulf Power's system. As shown in the following table, under EPA's final rule, Gulf Power's annual allocation is 56% smaller than its actual 2010 emissions. EPA models Gulf Power's units to operate at a 36% lower NOx emissions rate on average.

Plant	2010 Actual Emissions (tons)	2012 & 2014 Allocation	EPA Remedy 2012 (Forecasted)	EPA Remedy 2014 (Forecasted)	Delta Tons from 2010 Actual	% Change Tons 2010 Actual to 2012 Proposed	2010 Actual NOx Rate lb/mmbtu	2012 Allocated NOx Rate lb/mmbtu	Delta Rate from 2010 Actual	% Change Rate 2010 Actual to 2012 Proposed
Crist	2,769	1,260	1,374	1,571	(1,509)	-55%	0.180	0.101	(0.079)	-44%
Lansing Smith	1,604	669	1,079	1,285	(935)	-58%	0.161	0.151	(0.010)	-6%
Scholz	213	84	225	277	(129)	-61%	0.570	0.108	(0.462)	-81%
Gulf Average Total	4,587	2,013	2,678	3,133	(2,574)	-56%	0.178	0.114	(0.064)	-36%

In addition, EPA apparently assumes that Georgia Power's Plant Kraft installs low NOx burners by January 1, 2012 to lower the NOx emission rate from 0.63 lb/mmBtu in the base case to 0.27 lb/mmBtu in the remedy case. As explained in more detail in UARG's petition for reconsideration, low NOx burner installations cannot occur by 2012. Additionally, a simple burner retrofit would not likely achieve the 0.27 lb/mmbtu emission rate. Any control strategy would have to be more aggressive and the retrofit would likely take even longer.

II. EPA's Application of Its Cost Effectiveness and Significant Contribution Test Is Unlawful and EPA Arbitrarily Abandons the Stated Test when Setting Some State Budgets.

A. EPA's Application of Its Cost Effectiveness and Significant Contribution Test Is Unlawful.

The good neighbor provision obligates EPA to ensure that state implementation plans "contain adequate provisions prohibiting … 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 [NAAQS]." CAA § 110(a)(2)(D). EPA is directed to "measure each state's significant contribution to specific downwind nonattainment areas and eliminate them in an isolated state-by-state manner." *North Carolina*, 531 F.3d at 907. EPA may consider costs. *North Carolina*, 531 F.3d at 917 (citing *Michigan v. EPA*, 213 F.3d 663, 677, 679 (D.C. Cir. 2000)) ("EPA may 'after [a state's] reduction of all [it] could cost-effectively eliminate[],' consider 'any remaining contribution' insignificant."). But it cannot "just pick a cost for the region and deem 'significant' any emissions that sources can eliminate more cheaply." *North Carolina*, 531 F.3d at 918.

In this rule, despite clear guidance from the D.C. Circuit, EPA applies its cost-effectiveness analysis on a regional basis and wholly fails to consider *each* state's contribution of emissions to downwind air quality when establishing the budgets. Indeed, this fundamental legal flaw – along with others – is a primary reason EPA should stay this rule and take the time needed to make the rule both technically and legally defensible. Otherwise, EPA will simply find itself on a familiar path – implementing a rule likely to be found illegal.

In the final rule, EPA utilizes a two part test to link states to downwind areas and then to set the state budget. In step one, EPA models the downwind impacts of all anthropogenic emissions from a state to determine whether those emissions exceed the threshold value of 1% of the given NAAQS at a downwind receptor.[20] The state-specific analysis of downwind impacts ends there.

In step two, EPA attempts to "draw the line" between significant and insignificant contribution. *See North Carolina*, 531 F.3d at 918. To do so, EPA models EGU emissions at various cost thresholds (e.g., $500/ton NOx) and, based on a multi-factor assessment, selects a cost threshold that will determine each state's significant contribution. EPA's selection of the cost thresholds is effectively a regional analysis. EPA evaluates cost-thresholds and associated emission reductions on a multi-state basis and then assesses the air quality impacts of the combined, multi-state reductions on each receptor.[21] Thus, in defining "significant contribution" and setting the size of the budgets, EPA makes no attempt to determine a single state's contribution of emissions to another state. By picking a regional cost threshold and applying it to each state, without considering each state's contribution of emissions, EPA has "pick[ed] a cost for the region and deem[ed] 'significant' any emissions that sources can eliminate more cheaply."[22] *North Carolina*, 531 F.3d at 918.

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[20] In our comments on the proposed rule and in other contexts, the Company has raised its significant concerns about EPA's use of this extraordinarily low threshold. That threshold applied to these air quality standards is likely below the detection capability of existing modeling and measurement tools. *See* Southern Company, Proposed Transport Rule Comments at 34 (Oct. 1, 2010). *See also Michigan v. EPA*, 213 F.3d at 684 ("While we uphold EPA's determination that a 'significant' contribution is a cost-effectively controllable contribution, EPA must first establish that there is a *measurable [air quality] contribution*. Interstate contributions cannot be assumed out of thin air.") (emphasis supplied).

[21] As EPA explains, "[f]or each receptor, EPA quantified the … reduction and air quality improvement when a group of states consisting of the upwind states that are 'linked' to the downwind receptor … and the downwind state where the receptor is located, all made the … emission reductions that EPA identified as available at each cost threshold. EPA assumes reductions at each cost threshold from the linked upwind states as well as the downwind receptor state to assess *the shared responsibility of these upwind states* to address air quality at the identified receptor." 76 Fed. Reg. at 48,254 (emphasis supplied).

[22] The 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." *North Carolina*, 531 F.3d at 921.

Through this process, EPA can determine that ten states, including Alabama,[23] are linked to air quality concerns at a receptor in Michigan (via step one). EPA can also claim that if Michigan and all of the ten linked states invest $500/ton in SO2 and NOx removal, the air quality concerns at that receptor go away. But EPA cannot determine whether any SO2 or NOx reductions in Alabama were required to obtain that result. Nor can EPA determine whether a lower cost investment by Alabama sources (e.g., $100/ton) would achieve the same result. Thus, EPA cannot demonstrate to Alabama whether or not it is being forced "to share the burden of reducing other upwind states' [significant contribution]." *See North Carolina*, 531 F.3d at 921. Therefore, as applied in this rule, EPA's test fails to identify each state's significant contribution and is unlawful.

B. EPA Fails to Apply Its Significant Contribution Test Consistently, Effectively Requiring Some States to Spend Substantially More than EPA's Selected Cost Threshold.

For the reasons stated above, EPA's cost-effectiveness test does not met the standards of the Clean Air Act's good neighbor provision or the D.C. Circuit's order and is therefore illegal. Even if it were legal, EPA's selective departure from the test is arbitrary.

According to EPA, state budgets reflect emissions remaining in a state after eliminating all SO2 and NOx emissions that can be reduced at $500 per ton.[24] This does not describe the budgets for Florida, Georgia, and Mississippi.[25] For each of those states, EPA departed from its stated test (i.e., it did not simply apply the cost per ton constraint and let the model run) in various ways. The results arbitrarily injure these states' budgets and dramatically increase the cost of compliance (well above $500 per ton).

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[23] The ten states are Alabama, Illinois, Indiana, Kentucky, Missouri, New York, Ohio, Pennsylvania, Tennessee, Wisconsin, and West Virginia.

[24] This is a slight oversimplification, as the budgets reflect the emissions remaining after investing $500 per ton to eliminate each pollutant for each applicable program cumulatively, and the 2014 budgets assume Group 1 states are investing $2,300 per ton to eliminate SO2. For purposes of this discussion the oversimplification is sufficient.

[25] EPA's flawed approach to developing Florida's budget is explained in detail in the petition to reconsider and stay filed by The Florida Electric Power Coordinating Group ("FCG"), which is incorporated herein.

1. EPA Arbitrarily Abandons Its Stated Test in Setting Georgia's Phase II (2014) Budgets.

EPA abandons its cost-effectiveness test for Georgia and requires Phase II (2014) reductions for reasons that have nothing to do with cost-effectiveness or significant contribution. In the proposed rule, Georgia was included in Group 1 and, like other Group 1 states, faced a significant drop in its SO2 budget from 2012 to 2014. EPA justifies the decrease for Group 1 states on the grounds that additional reductions are necessary to address remaining PM-2.5 nonattainment problems in areas linked to the Group 1 states.

In the final rule, however, EPA moved Georgia from Group 1 to Group 2 yet retained a significant Phase II reduction in Georgia's SO2 budget. In fact, in the final rule, all of Georgia's Phase II final budgets drop significantly. From 2012 to 2014 Georgia's budgets drop by 63,296, 21,470 and 9,665 for the SO2, Annual NOx and Ozone NOx programs respectively. This represents a 40% reduction in Georgia's SO2 budget and 35% reductions in Georgia's two NOx budgets from 2012 to 2014. In contrast to the proposal, EPA provides an entirely new rationale for these Phase II reductions in Georgia – the further reductions are necessary to ensure that reductions required by Georgia's Multi-Pollutant Rule are not emitted by other sources in Georgia. In the preamble, EPA explains:

> If EPA did not adjust 2014 budgets to account for other emission reductions that would occur even in the baseline, other sources within the state would be allowed to increase their emissions under the unadjusted Transport Rule budgets to offset the emission reductions planned under other requirements such as state rules. Therefore, to prevent the Transport Rule from allowing such offsetting of emission reductions already expected to occur between 2012 and 2014, EPA is establishing separate budgets for 2012 and 2014 in the final Transport Rule *to capture emission reductions in each state that would occur for non-Transport Rule-related reasons* (i.e., in the base case) during that time.

76 Fed. Reg. at 48,261 (emphasis supplied). This explanation is nothing short of an admission that EPA has no Clean Air Act authority to require these reductions, yet it chooses to require these reductions simply by modeling them.[26] In doing so, EPA unlawfully federalizes Georgia's Multi-Pollutant Rule and punishes the significant investment Georgia's rate payers have made – and continue to make – in reducing

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[26] EPA failed to perform an analysis of the downwind air quality impacts associated with the 2012 budgets. Thus, there is nothing in the record that demonstrates an air quality basis for Georgia's reduced 2014 budgets.

SO2 and NOx emissions. The cost of these state-mandated reductions far exceeds EPA's $500 per ton cost threshold.[27]

EPA thus departs from the cost-effectiveness and significant contribution methodology it uses for all other states and relies on an entirely new methodology for establishing the Phase II Georgia budgets. And it does so only in the final rule, denying any opportunity for review and comment on this methodology. Furthermore, it appears EPA has singled out Georgia for this differential treatment even though other states have sources subject to future reductions. Georgia is the only Group 2 state with a lower SO2 budget in Phase II. This change is of central relevance to the rule as applied to Georgia because it establishes the emission reduction requirement for sources in Georgia in 2014 and beyond. This new methodology also effectively punishes the State of Georgia's proactive efforts to reduce emissions.[28]

The good neighbor provision grants EPA the obligation to ensure that SIPs eliminate significant contribution. EPA's authority stops there. The good neighbor provision affords no authority for EPA to prevent the offsetting of emission reductions required by state law.[29] EPA sets state budgets at a level that reflects the removal of significant contribution. Georgia's state budgets, however, reflect the removal of the alleged significant contribution plus the removal of emissions associated with Georgia's Multi-Pollutant Rule reductions – without consideration of cost. Reducing Georgia's budget to federalize these state-level reductions only compounds the insult to cooperative federalism.

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[27] As EPA well knows, the Georgia Multi-Pollutant Rule requires installation of scrubbers and SCRs on numerous units.

[28] Assuming for purposes of argument only that EPA has the authority to eliminate significant contribution *plus something else* (i.e., more than significant contribution), which it attempts to do, EPA acts arbitrarily by treating proactive state rules the same as injunctive relief achieved through federal enforcement. In stark contrast to consent decrees, state rules result from a conscious choice by the state to improve air quality – e.g., to be a good neighbor. EPA must reconsider that policy choice and the potential chilling effect it may have on proactive state rules.

[29] If these reductions are warranted for state air quality, then Georgia – and not the federal government – can choose to require them. *Union Elec. Co. v. EPA*, 427 U.S. 246, 269 (1976)("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."). *See also*, *North Carolina*, 531 F.3d at 917-18 (rejecting EPA's valid goal of preserving the viability of the Clean Air Act's Acid Rain Program as not being "among the objectives in [the good neighbor provision].")

2. EPA Arbitrarily Abandons Its Stated Test to Set Mississippi's Budget.

EPA also arbitrarily abandons its cost-effectiveness framework in setting the ozone season NOx budget for Mississippi.[30] Mississippi's budget bears no correlation to emissions that can be reduced at the $500/ton cost threshold. Instead, in the final rule, without opportunity for public review and comment, EPA set the Mississippi budget at projected 2012 *base case* emissions, which represents a 39% reduction from the proposed budget and a 37% reduction from 2010 actual emissions. This result was completely unpredictable, and the final rule contains no analysis that this significantly reduced emissions budget is achievable at EPA's stated $500 per ton threshold. In fact, EPA's explanation of how it set the budget calls into question whether Mississippi should even be included in the final rule.

The final rule sets Mississippi's ozone season NOx budget (applicable in 2012 forward)) at 10,160 tons, which is equal to the emissions EPA projects for Mississippi in its *2012 base case runs* (i.e., business as usual, without CAIR).[31] When EPA modeled reductions available at $500 per ton for purposes of determining the remedy case budget, the model projected *increases* in emissions for Mississippi – from 10,160 tons in the base case to 10,639 tons for 2012 and 10,960 tons for 2014.[32] Thus, at the end of its standard analysis to *quantify* significant contribution based on cost-effective ($500 / ton) reductions, EPA found that Mississippi emissions might actually increase with the addition of cost-effective controls. This result calls into question whether Mississippi should even be included in the final rule because it suggests that Mississippi's significant contribution is a negative value.

EPA Emission Projections for Mississippi		
	2012	2014
Base Case Without CAIR in Place	10,160	11,212
Remedy Case With $500/ton Cost Threshold	10,639	10,960
Special Case Without Mississippi in the Final Rule	10,647	11,450

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30 Our comments here and EPA's abandonment of its cost-effectiveness analysis are equally relevant to Arkansas, Indiana, Louisiana and Maryland. *See* 48,263.

31 76 Fed. Reg. at 48,263. EPA's 2014 base case projection for Mississippi was 11,212 tons. *See* "TR_Base_Case_Final State Emissions" (available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html).

32 *See* "TR_Remedy_Final State Emissions" (available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html).

Rather than using the remedy case projections, based on $500 per ton reductions, as the final budget for Mississippi, EPA took a completely different approach. EPA departed from its stated framework and modeled the impacts of its final rule on Mississippi EGU emissions, assuming Mississippi and four other states were not in the Ozone NOx program. That analysis showed that due to emission leakage Mississippi's emissions would increase slightly to 10,647 and 11,450 for 2012 and 2014 respectively.[33] That is, EPA's analysis showed that if Mississippi and four other states were removed from the rule, Mississippi's emissions would increase by eight tons in 2012 and 490 tons in 2014 as compared to the final rule's remedy case. Based on this analysis, EPA determined that Mississippi had to be in the rule because if EPA finalized the CSAPR, emissions in Mississippi could increase (albeit by a nominal amount). To prevent this result, rather than setting the budgets at the remedy case levels, consistent with the $500 per ton investment, EPA simply set the Mississippi ozone season NOx budget at projected 2012 base case emissions. EPA provides no evidence whatsoever that the projected base case 2012 emissions, which represent a significant reduction from both the proposed budget and 2010 actual emissions, are achievable at $500 per ton. Had EPA included these analyses in any of the proposals, Southern Company and Mississippi Power would have explained that these 2012 reductions are not available at $500 per ton and that EPA's modeling demonstrates that there is no basis for including Mississippi in the final rule. These analyses and resulting budget revisions are obviously central to the final NOx emissions budget for Mississippi and given that this alternative methodology appears for the first time in the final rule, Southern Company did not have an opportunity to comment on it. Therefore Mississippi's budget must be reconsidered.

EPA must also re-evaluate whether Mississippi is properly included in the final rule. One way to view EPA's analysis with respect to the inclusion of Mississippi is to note that it first identified a linkage to downwind air quality concerns. It then quantified Mississippi's significant contribution and determined that value to be less than zero. Rather than view this as a flaw in its methodology and modeling, EPA performed additional modeling in an attempt to justify inclusion of Mississippi in the rule. That justification, however, has no basis in the good neighbor provision as interpreted by EPA in the final rule. Every projection EPA has for Mississippi shows insignificant contribution from EGUs. Yet EPA arbitrarily includes Mississippi in the rule – without any analysis showing significant contribution as defined in the final rule – and selects the lowest of six projected values as Mississippi's budget. EPA's justification for including Mississippi is arbitrary and capricious and undermines the legal integrity of EPA's action.

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[33] 76 Fed. Reg. 48,263; *see* "TR_uncontrolled_ozone_states_Final State Emisions" [EPA-HQ-OAR-2009-0491-4438].

III. EPA Should Reconsider Its Aggressive Compliance Timeline and Its Decision to Bypass the States.

One of our most urgent concerns with the final rule is its unprecedented and disruptive compliance timeline. In comments on the proposed rule, Southern Company outlined the many reasons EPA must abandon its aggressive timeline. The Company explained that a five-month compliance planning window did not allow time for states to develop state implementation plans; that a longer period was needed to allow stable allowance markets to develop; that a longer period of time was needed to develop and implement compliance strategies;[34] and that EPA's haste was not mandated by the D.C. Circuit's *North Carolina* order and was not justified from an air quality standpoint because CAIR was in place and achieving real emission reductions and air quality improvements.

In the final rule, EPA did not accommodate these very real concerns. Worse, it significantly reduced the state budgets. Those budget reductions dramatically compound the compliance planning challenges. The challenges are further compounded by EPA's decision to enforce the rule's assurance provisions in 2012 instead of 2014. Put plainly, EPA acts recklessly. It seeks to impose some of the most stringent SO2 and NOx budgets in the history of the Clean Air Act and seeks compliance on an unprecedented timeline – the most aggressive for an interstate transport rule by orders of magnitude.

The Clean Air Act's Acid Rain program allowed four years for compliance planning and market development. The NOx SIP Call allowed 4.5 years for compliance after the federal rule was finalized. The CAIR NOx program allowed 3.5 years for phase I compliance, while the CAIR SO2 program allowed 4.5 years for phase I compliance. CAIR's phase II compliance deadline was 9.5 years after promulgation of the final rule. The historical average for phase I compliance is 50 months in EPA good neighbor provision rulemakings. In this case, EPA allows five months to comply with the CSAPR's phase I deadline for annual SO2 and NOx reductions.

CSAPR budgets are much more stringent than the CAIR budgets for some states. For example, Georgia's SO2 CSAPR budget is 54,530 tons lower than its CAIR budget for 2012 and 2013. Georgia's 2014 SO2 CSAPR budget is 117,826 tons lower than its CAIR budget for that same year, and 53,909 tons lower than its CAIR budget from 2015 on. Thus, in the first three years of the program alone, Georgia sources will receive 226,886 fewer SO2 allowances under the CSAPR (with its much more limited trading provisions).

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[34] We explained that five months did not allow time for EPA's assumed near term compliance strategies. We could not switch fuels because of contractual commitments. We could not adequately evaluate procedures and local reliability concerns needed to redispatch the system. And we certainly could not install controls.

For the reasons stated in the Company's original comments, Southern Company urges EPA to reconsider its aggressive timeline. The following sections highlight a few of those key reasons.

A. EPA's Aggressive Timeline Undermines the Legal Integrity of the Rule.

EPA's aggressive timeline necessarily leads to a "FIP first" approach. As explained in numerous public comments, petitions to reconsider, and judicial filings, EPA does not have the authority to bypass the states in this manner. "The states are responsible in the first instance for meeting the NAAQS through state-designed plans that provide for attainment, maintenance and enforcement of the NAAQS." This structure gives states "authority to make the many sensitive technical and political choices that a pollution control regime demands." *NRDC v. Browner*, 57 F.3d 1122, 1123-24 (D.C.Cir. 1995). By adjusting its timeline, EPA can allow states the opportunity to develop SIPs in the first instance and eliminate this basis for judicial challenge.

B. EPA's Haste, the Legal Uncertainty of the Rule, and EPA's Abbreviated SIP Process Undermine Allowance Market Integrity.

EPA may believe, that it has resolved the SIP issue by offering states the opportunity to implement very limited allocation SIPs for 2013 and less limited SIPs thereafter. We disagree.[35] More importantly, EPA's haste, and indeed the limited SIP process itself, significantly undercuts the stability of the allowance markets.

As objective market participants, we have very serious doubts about the near and long term stability and liquidity of the rule's allowance markets. First, as noted, the fundamental legal flaws undermine the mid- to long-term stability of the market. We anticipate vacatur of the program all together and a revival of CAIR, or, at best, a remand requiring EPA to fix the fundamental legal and technical flaws, which would impact allowance budgets and allocations as well as which states are in which programs. Given these significant uncertainties, we are much less likely to participate in the markets to any meaningful degree in the near term.

Second, this is the first EPA trading program to include a hard cap above which we may – depending on variables outside of our control – be required to surrender two additional allowances per ton of emissions. That possibility further discourages market participation. Third, two of our states – Alabama and Georgia –

[35] The Clean Air Act affords states the first opportunity. Some limited opportunity in the future cannot resolve EPA's usurpation of that first opportunity.

have been placed in an extraordinarily confined Group 2 SO2 market. There are only five other states with which to trade and based on actual 2010 SO2 emissions, it appears that there is a net deficit of allowances in this trading group, which would obviously prevent development of a market in Group 2 states. Based on historical emissions, Texas' demand for SO2 allowances alone will overwhelm any market that does develop.

Finally, EPA's abbreviated SIP process creates additional uncertainty. States must be authorized to develop SIPs on the front end of the rulemaking process. Delaying states' their statutory right to develop their own SIPs until after the rule has been implemented means that only the 2012 allocations are certain. Allowing states limited rights to reallocate allowances in 2013 and greater flexibility in later years creates significant uncertainty with respect to what allowances may or may not be available in future years and inhibits trading and thus delays market stability.

C. EPA's Haste Is Unwarranted because CAIR Is in Place and Air Quality Trends Show an Improvement.

There is no air quality basis for EPA's rush to replace CAIR. As discussed in detail in Section V below, CAIR remains in place and continues to achieve emission reductions and air quality improvements. In fact, all of the air quality monitors to which Alabama, Florida, Georgia, and Mississippi are "linked" now have attaining air quality.[36]

IV. EPA Should Reconsider the Unintended Consequences of Its Revised Assurance Provisions on New Units and Purchased Power.

In the final rule, EPA announces several changes from the proposed rule's assurance provisions. These changes, likely unintentionally, place an untenable and unjust financial risk on new units and impact purchased power agreements ("PPAs") in ways that could unnecessarily limit reliance on efficient, low-emitting, generation.

A. New Units

Under the rule, new units must go through an annual process for obtaining their allowance allocation for the year from the limited new unit set aside. Through this process a new unit's allocation varies from year to year, and, in years where the demand for new unit allowances exceeds the availability, new units could be

[36] These monitors are in or near Atlanta, GA, Baton Rouge, LA, Birmingham, AL, Butler, OH, Cincinnati, OH, Detroit, MI, Houston, TX, and Marion, IN.

severely under-allocated. That under-allocation is itself problematic, but the new assurance provisions significantly exacerbate the problem.[37]

The final rule is not clear with respect to how a new unit's individual assurance level would be determined after the unit's first year of operation.[38] One interpretation would be that it is determined the same way a designated representative's ("DR") assurance level is determined (i.e., allocation plus variability). If true, not only would a new unit's allocation change from year to year, but its assurance level would shift from year-to-year as well, creating significant uncertainty and risk. For example, in a year in which a new unit is severely under-allocated, it could trigger the assurance penalty provisions simply through normal operations.

For simplicity, take for example a new unit that has a designated representative who has no other units in that state. If that unit's typical operations result in 100 tons of ozone season NOx emissions, it would typically (through EPA's new unit allocation process) receive about 100 allowances and its assurance level would be about 121 tons. If, however, new unit allowances become scarce and it is under-allocated, for example if it receives only 50 allowances, then arguably its assurance level would be approximately 60 tons for that year (i.e., 121% of its allocation). Thus, for normal operations (~100 tons) that unit would be required to surrender 180 allowances (100 allowances, plus two additional allowances for each ton over the unit's assurance level).[39] That result is untenable.[40]

New units are almost always required by the Clean Air Act to achieve extraordinarily stringent emission limitations through the installation of Best Available Control technology (BACT). There is virtually no opportunity for such units to reduce emissions beyond these levels. The rule should encourage them to

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37 As proposed for comment in the third NODA, the final rule imposes the assurance provision penalty at the designated representative ("DR") level. In the final rule, the penalties have doubled, requiring the surrender of two additional allowances for any emissions over the state's assurance level (i.e., a three to one surrender rate), and EPA has abandoned its initial grace period meaning that the penalties apply in the first year of the rule – 2012. The impact of this combination of changes is significant, and we have not had the opportunity to comment on their collective impacts.

38 The final rule provides for a surrogate assurance level for new units, but it only applies to the unit's first year of operations. 76 Fed. Reg. at 48,295. The rule is silent on the issue of how to determine a new unit's assurance level after that initial year.

39 This assumes that the state exceeds its assurance level in that same year and that the new unit's actual assurance penalty is not discounted (e.g., because the statewide assurance level was not exceeded to the same extent that the new unit's assurance level was).

40 The assurance provisions are designed to, among other things, provide "sources with flexibility to manage growth and electric reliability requirements …." 76 Fed. Reg. at 48,295. New units are denied that flexibility in years when they happen to be under-allocated.

run. The potential to face three-for-one allowance surrender requirements for a significant portion of normal operations, however, discourages dispatch of efficient, low emitting units.

EPA should reconsider the impact of its new assurance provisions on new units and either extend its surrogate approach for determining new unit assurance levels to make that approach applicable whenever a new unit is under-allocate or establish perpetual allocations for new units after a certain period of operation. That perpetual allocation, however, should be added to the state budget and not deducted from other units. Again these are well-controlled and efficient units. By allowing new units to receive a perpetual allocation on top of the state budget, EPA allows the rule to accommodate energy demand increases where a need has been demonstrated, without adverse air quality impacts.

B. Purchased Power Agreements.

The final assurance provisions also unnecessarily complicate purchased power agreements ("PPAs"). Our retail operating companies operate in a tight power pool that dispatches all of our generating resources to meet the aggregate load of the companies. In addition to our owned and operated on-the-ground generating capacity, the system includes generation available through PPAs with wholesale power producers. Though it varies from contract to contract, our operating companies typically provide these power producers with either a payment for allowances or with allowances to cover the emissions associated with our power purchases. Without the assurance provisions, this is a simple process; we transfer money or allowances.

The assurance provisions, however, may significantly complicate this process and discourage economic dispatch, thereby further increasing the cost of compliance and electric rates. For instance, dispatching an efficient gas-fired combined cycle pursuant to a PPA may be more cost-effective and result in lower SO_2 and NOx emissions than dispatching other company-owned on-the-ground capacity. However, if that power producer has a limited pool of generation in the state, it may have significant assurance provision exposure that could inhibit operation of that otherwise cost-effective unit. The situation would be even worse if the unit is a "new unit," as explained above. Either way, the final rule sets up a situation where some of the lowest-emitting power resources may be constrained by the assurance provisions and therefore not fully utilized.

Wholesale power producers in particular may also be more exposed to assurance provision risk because, while they may have significant resources across broad regions, the number of resources in any given state may be limited, thus increasing their exposure to assurance provision risk. For example, Southern Power, a Southern Company subsidiary, is a wholesale power producer that currently operates one facility in North Carolina.[41] Southern Power owns and operates very-efficient, low-emitting natural gas-fired generation, which could be dispatched above historical levels because of this rule. While Southern Power shares a DR with other Southern subsidiaries, there are no other Southern subsidiaries in North Carolina. Because its assurance penalty risk in North Carolina is not pooled with any other assets, its units will be at greater risk and, as a result, may be unnecessarily constrained. Again, there are strong policy reasons to avoid that constraint – reduced emissions, lower cost of electricity, and more uniform dispatch protocols.

EPA suggests in the final rule that utilities can mitigate this assurance penalty risk by taking advantage of the "common DR approach or [by] pursu[ing] similar private arrangements with each other to cover their emissions at the lowest possible cost." 76 Fed. Reg. 48,295. The common DR approach is unworkable in this context for numerous reasons. For example, the DR is responsible for certifying to numerous compliance obligations under, not only CSAPR, but also the Acid Rain Program and the greenhouse gas reporting program. A Southern Company or operating company DR cannot sign off on CEMS certifications, required reports or certify to other regulatory obligations for a company over which it has no control and no access to information.

This change to the assurance provisions in the final rule and the uncertainty in the assurance provisions for new units have an immediate impact on existing PPAs and add significant complexity to new PPAs going forward. EPA should re-propose these provisions for public review and comment in an effort to find a workable solution to these problems.

V. EPA Should Stay the Rule Pending Reconsideration and/or Judicial Review.

Southern Company Services, on behalf of its operating companies, respectfully requests that EPA stay this final rule pending reconsideration and/or judicial review. Authority for granting a stay derives from Section 307 of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B), and the APA, 5 U.S.C. § 705. The Clean Air Act authorizes EPA to stay the effectiveness of a final rule for three months if a reconsideration proceeding is convened, and the APA authorizes EPA to postpone the effectiveness of a rule pending judicial review when "justice so requires". 42 U.S.C. § 7607(d)(7)(B); 5 U.S.C. § 705. As EPA has recently acknowledged, the

41 Southern Power owns and operates Plant Rowan in Salisbury, North Carolina. It is constructing an additional facility in Cleveland County, which will include four, gas-fired, combustion turbine units.

Agency has broad discretion to delay the effective date of a rule based on the specific facts and circumstances before it. *Industrial, Commercial, and Institutional Boilers and Process Heaters and Commercial and Industrial Solid Waste Incineration Units*, 76 Fed. Reg. 28,662 (May 18, 2011). EPA has interpreted this APA standard differently from the standard for judicial stays. 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 at 13-14, in *Sierra Club v, Jackson*, No.1:11-cv-01278-PLF (D.D.C. August 25, 2011).

EPA recently applied the APA standard for reconsideration in the context of the final Industrial Boiler MACT and CISWI Rules. In that case, the Agency indicated that a stay is appropriate when (1) the public had insufficient notice and opportunity for comment on certain revisions to the proposed rules, (2) data were 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 the 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. 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 August 25, 2011). These and similar factors justify a stay of CSAPR. Furthermore, a stay will not result in any harm to the public interest because CAIR can remain in place and continue to protect public health and the environment pending EPA's reconsideration and judicial review.

A. Justice Requires a Stay of CSAPR

As discussed in detail above, EPA's final rule is dramatically different from the proposed Transport Rule in many respects. Of greatest concern, the emissions budgets for Florida, Georgia and Mississippi were substantially reduced as compared to the proposal. Southern Company and its operating companies did not have sufficient notice and opportunity to comment on those changes. The revised budgets are based on numerous incorrect inputs and assumptions, some of which Southern Company commented on with no response from the Agency and others which were simply impracticable to comment on given the sheer volume of information and limited time provided for review. Some elements were introduced for the first time in the final rule and were not a logical outgrowth of the proposal.

Furthermore, as this petition and others like it illustrate, important data that form the foundation for the emissions budgets are riddled with errors and thus the budgets are fundamentally flawed. Revisions are required. EPA has acknowledged the need for corrected data and revisions to the budgets in its recently proposed rule making adjustments to the final budgets. U.S. Environmental Protection Agency, Revisions to the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, Proposed Rule, RIN 2060-AR22

(October 6, 2011). In addition to proposing corrections to the final budgets for nine states, the proposed rule includes a process for seeking additional amendments to state budgets. Id.

Finally, the rule should be stayed because it will force affected sources to begin taking irreversible actions now to achieve compliance. The compliance deadline for the annual program is only three months away and the deadline for the ozone season program is only seven months away. This unprecedented implementation schedule severely limits the companies' compliance options, forcing (1) reliance on brand new allowance markets that have not yet developed; (2) possible re-dispatch of generation for compliance as opposed to cost; (3) immediate renegotiation of numerous contracts and (4) payment of liquidated damages under fuel transportation contracts and other agreements.

Given the lack of lead time before the rule becomes effective, many sources will have to rely for compliance on an immature allowance market. Experience with new allowance markets under the Clean Air Act over the past 20 years demonstrates that emerging markets are highly volatile. That volatility results in higher prices than in established markets. The CSAPR SO2 and NOx markets are expected to be more illiquid and volatile than under previous programs for a number of reasons, including: (1) the much shorter compliance lead time, which prevents development of the market in advance of allowance needs; (2) the significant limits on trading (geographic limits for SO2 and volume limits for both SO2 and NOx); and (3) the significant uncertainty surrounding the legality and ultimate viability of this rule. Recent allowance trades demonstrate that allowance prices are much higher than EPA's projections. CSAPR Annual and Seasonal NOx allowances first traded in late August for $3750 per ton, and Group 1 SO2 allowances traded in late August for $2600 per ton. We are not aware of any recorded trades since that time. In the states in which each of the companies operate, the cost of allowance purchases are borne by customers.

EPA itself predicts the rule will increase electricity costs by 0.9 percent in the Southern Company service territory in 2012 and another 0.5 percent by 2014. See Regulatory Impact Analysis (RIA) for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States (June 2011), at 266. While these percentages may not sound significant, consider that over 48 percent of Southern companies' customers make $40,000 a year or less. For these families and individuals, even small increases are significant. And these increases obviously come at a time when many customers can least afford them. A stay is required to prevent these unnecessary adverse impacts.

B. A Stay Will Not Result in Any Harm to the Public Interest Because CAIR Can Remain in Place and Continue to Protect Public Health and the Environment.

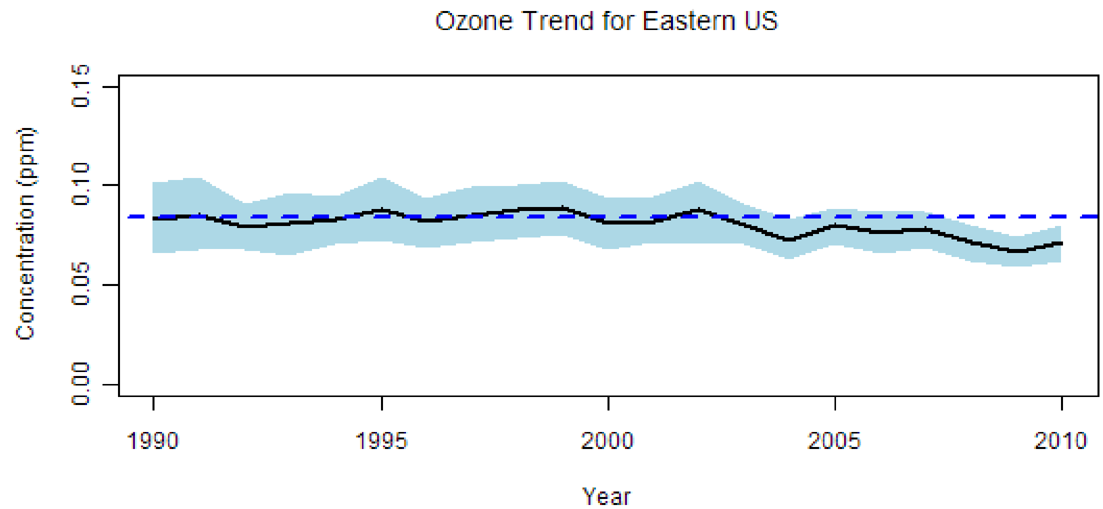
Staying CSAPR pending reconsideration and judicial review will not result in any significant harm to public health or the environment because the stay will not affect the measures states have implemented to attain and maintain the ozone and PM-2.5 standards, and CAIR will remain in place and achieve air quality results similar to those EPA projects from CSAPR. In fact, EPA urged the DC Circuit to leave CAIR in force and effect pending the remand rulemaking to help ensure continued air quality improvements. See *North Carolina v. EPA*, 550 F. 3d 1176, 1177 (D.C. Cir. 2008). And, the Court specifically declined to set a deadline for a CAIR replacement. Id. The Court ultimately agreed. According to the Court, "allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would . . . preserve the environmental values covered by CAIR." Id. at 1178.

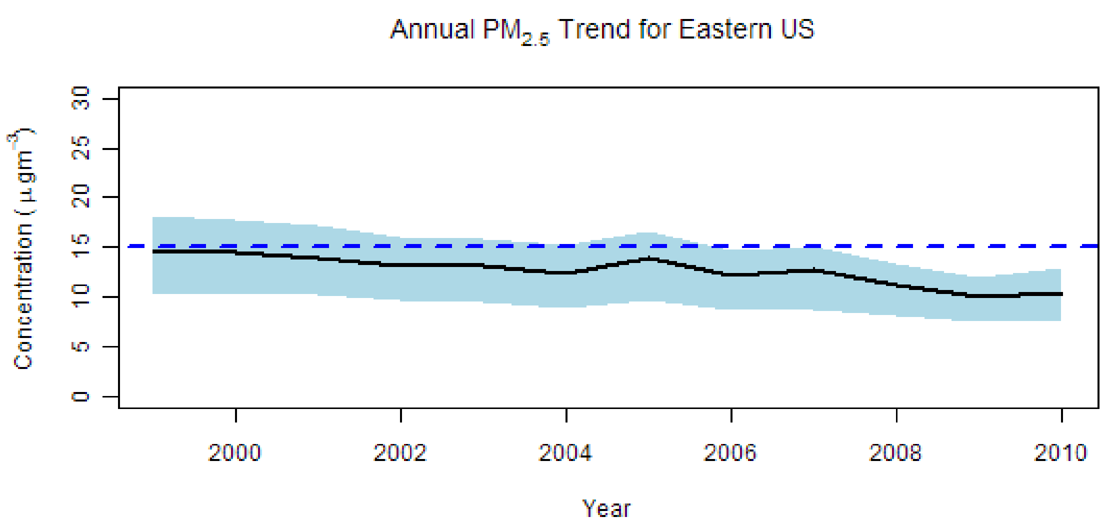
More recently, in its June 2011 Regulatory Impact Assessment (RIA) for CSAPR, EPA confirms that state regulations and CAIR are achieving emission reductions and improving air quality. According to EPA, "CAIR is continuing to help states address ozone and PM-2.5 nonattainment and improve visibility by reducing . . . SO2 and NOx through the implementation of three separate cap and trade compliance programs for annual NOx, ozone season NOx, and annual SO2 emissions from power plants." RIA at 233. In the RIA, EPA describes some of the federal consent decrees and state programs in place to reduce emissions and concludes that "both federal and state efforts are continuing to bring about sizeable reductions in SO2 and NOx from the power sector." RIA at 234. Finally, EPA notes that "[b]ecause CAIR remains in effect until it is replaced, emission reductions continue in the eastern US." RIA at 244.

CAIR is providing significant air quality benefits in the form of reduced ozone and PM-2.5 levels, including attaining air quality under both standards in many designated nonattainment areas. CAIR will provide similar benefits to CSAPR in 2012 and 2013 while the rule is being reconsidered and evaluated by the court.

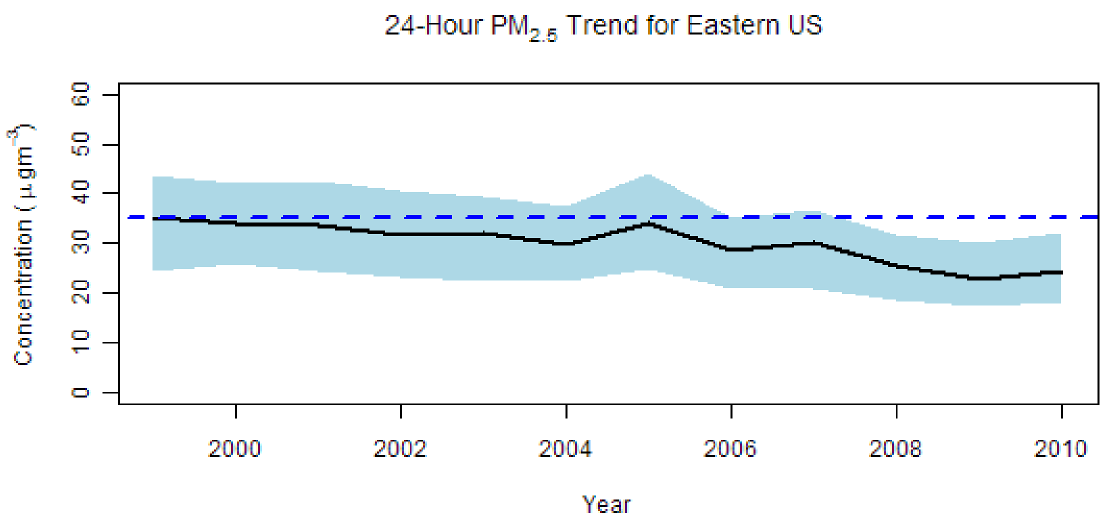
EPA's own air quality trends analyses illustrate that ozone and PM-2.5 levels across the nation have improved significantly. Between 1990 and 2009 (the first year of CAIR compliance) ozone levels have decreased on average by 21 percent. See http://www.epa.gov/airtrends/ozone.html. And between 2000 and 2009, PM-2.5 levels have decreased on average by 27 percent. See http://www.epa.gov/airtrends/pm.html.

The picture is even more dramatic if we focus on the Eastern US and include 2010. The plots below for ozone, annual PM2.5, and daily PM2.5 show that greater than *ninety percent* of the monitors in the Eastern US are below the ambient standards that are the focus of this rule. Clearly CAIR is contributing to this positive trend.[42]





42 These trends charts use data from the EPA AQS datamart using the Direct Interface for downloading and selecting data only from states that are east of a meridian including North Dakota to Texas. The plots were created with the same criteria that are described at http://www.epa.gov/airtrends/interpret.html. They are consistent with the graphs that are currently in that document.



In fact, based on 2008 – 2010 monitored data as reported by EPA, only a very few ozone and PM-2.5 nonattainment areas actually remain in the region subject to CSAPR. Specifically, of the seven ozone nonattainment areas CSAPR is designed to address, only three areas were monitoring nonattainment levels in 2008 – 2010. Of the twenty daily PM-2.5 nonattainment areas CSAPR is designed to help, only five areas were monitoring nonattainment in 2008 – 2010. Finally, of the twelve annual PM-2.5 nonattainment areas EPA identified in CSAPR, only one was monitoring nonattainment in 2008-2010. See 76 Fed. Reg. 48208, 48233-48236 (August 8, 2011).

While EPA projected many more nonattainment areas in its proposed Transport Rule and CSAPR, those projections assumed CAIR was not in place and assumed worst case allowable emissions. Therefore, those projections are not relevant to this analysis. Nonetheless, even a comparison of those projections in the proposed and final rules illustrates the inescapable conclusion that air quality is improving even before implementation of CSAPR. Comparing EPA's baseline projected nonattainment and maintenance areas for 2012 in the proposed rule to the baseline projected nonattainment and maintenance areas in the final rule shows a substantial reduction in the number of projected nonattainment and maintenance areas under all three standards. Table 1 below illustrates the projected reductions.

Table 1

		Projected Monitors in 2012	
NAAQS	Status	PTR	CSAPR
Annual PM2.5	Nonattainment	32	12
	Maintenance Only	16	4
Daily PM2.5	Nonattainment	92	20
	Maintenance Only	38	21
Ozone	Nonattainment	11	7
	Maintenance Only	16	9

As noted above, actual air quality, based on EPA's 2008 – 2010 monitored data, is much better than any of EPA's projections. As demonstrated in Table 2 below, the reality is that only a small fraction of the monitors projected to be in nonattainment are actually measuring nonattainment levels.

Table 2

	Number of Monitors above NAAQS	
NAAQS	Projected in 2012 w/o CAIR	2008-2010 Data
Annual PM2.5	12	1
Daily PM2.5	20	5
Ozone	7	3

Furthermore, many areas designated as nonattainment have already received formal clean data determinations and are on their way to being re-designated as attaining the 1997 and 2006 ozone and PM-2.5 standards. Table 3 specifically identifies nonattainment areas with which Alabama, Florida, Georgia and Mississippi are linked in the final rule. It demonstrates that all of those areas, according to EPA, now have attaining air quality or have been formally re-designated attainment under the standards at issue.

Table 3

Area	Annual PM2.5	24-hour PM2.5	Ozone
Atlanta, GA	Clean Data Proposed Rule 76 Fed. Reg. 56701 (September 14, 2011)	Designated Attainment Final Rule 74 Fed. Reg. 58688 (November 13, 2009)	Clean Data Final Rule 76 Fed. Reg. 36873 (June 23, 2011)
Baton Rouge, LA	Designated Attainment Final Rule 70 Fed. Reg. 944 (January 5, 2005	Designated Attainment Final Rule 74 Fed. Reg. 58688 (November 13, 2009)	Clean Data Final Rule 75 Fed. Reg. 54778 (September 9, 2010)
Birmingha m, AL	Clean Data Final Rule 76 Fed. Reg. 38023 (June 29, 2011)	Clean Data Final Rule 75 Fed. Reg. 57186 (September 20, 2010)	Re-designation Final Rule 71 Fed. Reg. 27631 (May 12, 2006)
Butler/ Cincinnati, OH	Clean Data Final Rule 76 Fed. Reg. 60373 (September 29, 2011)	Designated Attainment Final Rule 74 Fed. Reg. 58688 (November 13, 2009)	Re-designation Final Rule 75 Fed. Reg. 26118 (May 11, 2010)
Detroit, MI	Attaining Data (2008-2010) http://www.epa.gov/airtre nds/values.html	Attaining Data (2008-2010) http://www.epa.gov/airtre nds/values.html	Re-designation Final Rule 74 Fed. Reg. 30950 (June 29, 2009)
Houston, TX	Designated Attainment Final Rule 70 Fed. Reg. 944 (January 5, 2005)	Designated Attainment Final Rule 74 Fed. Reg. 58688 (November 13, 2009)	Attaining Data (2008-2010) http://www.epa.gov/air trends/values.html; see also Memorandum From Gina McCarthy to the Regions (September 22, 2011)
Marion, IN	Attaining Data (2008-2010) http://www.epa.gov/airtre nds/values.html	Designated Attainment Final Rule 74 Fed. Reg. 58688 (November 13, 2009)	Re-designation Final Rule 72 Fed. Reg. 59210 (October 19, 2007)

CAIR can be expected to achieve additional air quality improvements on par with CSAPR in 2012 and 2013. First, as demonstrated in Table 4 below, CAIR and CSAPR achieve similar total EGU emission reductions across the 30-state eastern US area subject to the rules.[43] Region-wide annual SO2 emissions under CAIR are almost equivalent to reductions under CSAPR. CAIR emissions are less than four percent higher than CSAPR, and annual NOx emissions are actually lower under CAIR than CSAPR.

[43] The thirty states were chosen to include any state that was covered by at least one of the three rules. For those states not covered by a particular rule the baseline (2012 or 2014) EGU emissions from the PTR was used.

Table 4

30-State EGU Emissions (Total)[1]				
	SO2		NOx	
Rule	2012	2014	2012	2014
CAIR	3,778,105	2,692,343	1,626,187	1,375,377
PTR	4,268,175	2,922,102	1,573,567	1,579,632
CSAPR	3,645,363	2,473,826	1,401,245	1,312,690
[1] EGU emissions in the 30 states that were included in at least one of the rules.				

CAIR and CSAPR do, however, differ significantly in the variability of emissions from state-to-state. Comparing the same 30-state area under the proposed and final rule as compared to CAIR, there are substantial differences in emissions on state-level basis. Some states are projected to emit more SO2 and / or NOx under CSAPR as compared to CAIR and some states would emit less. Comparing CSAPR to CAIR in 2012, the maximum increase in state-level emissions is 70,252 tons for SO2 and 20,937 tons for NOx. The maximum decrease comparing CSAPR and CAIR in 2012 is 142,763 tons of SO2 and 47,419 of NOx. These state-to-state differences, however do not significantly change the overall projected air quality results.

Notwithstanding state-level differences in emissions under the two rules, the CAIR and CSAPR emission budgets produce similar projected air quality improvements. Despite significant variability in emissions at the state level, CAIR and CSAPR result in roughly the same number of remaining nonattainment and maintenance areas in 2012 and 2014 based on EPA's own projections of CSAPR and our projections of CAIR using EPA's PTR AQAT and the CAIR budgets[44]. As demonstrated in Table 5 below, in 2012, EPA projects exactly the same number of daily and annual PM-2.5 nonattainment and maintenance areas under the two rules.

[44] Comments of Southern Company on the U.S. Environmental Protection Agency's proposed Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone (October 1, 2010), at p. 10.

Table 5

2010 DV vs. CSAPR vs. CAIR			
2010 DV			
	Monitors with Non-attaining Air Quality[1]		
Daily PM2.5	5		
Annual PM 2.5	1		
Ozone	3		
		Number of Monitors Determined to be	
NAAQS	Scenario	Nonattainment	Maintenance
2012			
Daily PM2.5	CSAPR[2]	2	9
	CAIR-1[3]	2	9
Annual PM 2.5	CSAPR[2]	1	1
	CAIR-1[3]	1	1
Ozone	CSAPR[4]	4	10
	CAIR-1[3]	8	18
2014			
Daily PM2.5	CSAPR[5]	1	5
	CAIR-2[3]	1	2
Annual PM 2.5	CSAPR[5]	0	0
	CAIR-2[3]	0	1
Ozone	CSAPR[5]	4	10
	CAIR-2[3]	N/A	N/A
[1]From http://www.epa.gov/airtrends/values.html. 2008-2010 Data			
[2]From Table VI.C-2 of CSAPR under assumption that the $500 per ton line is similar to the remedy for 2012. Likely a conservative estimate of actual remedy since it includes additional emissions reductions from Group 1 states @ $500 per ton.			
[3]Estimated using PTR AQAT. N/A = Not estimated. Assumed same as 2012 under assumption that EGU NOx budgets are very similar in 2012 and 2014.			
[4]From Table VIII.B-1 of CSAPR under assumption that EGU NOx budgets are very similar in 2012 and 2014			
[5]From Table VIII.B-1 of CSAPR			

The only difference between CSAPR and CAIR is the projected reduction in the number of ozone nonattainment and maintenance areas under the two rules. In reality, however, based on EPA's 2008-2010 data, only 3 ozone nonattainment areas actually remain today, which is lower than the projections for either CSAPR or CAIR. And as noted earlier, none of these are at monitors to which Alabama, Florida, Georgia, and Mississippi were originally linked. Further, the CSAPR-projected benefit of the "remedy" in 2014 at these monitors ranged from 0.0 to 0.3 ppb, seriously calling into question why an ozone season "remedy" for Alabama, Florida, Georgia, and Mississippi was required in the first place.

Finally, EPA's analysis of CSAPR benefits suggests that the benefits are not significant and lack credibility. EPA evaluated the health benefits of CSAPR in its RIA but only evaluated the benefits of CSAPR in the absence of CAIR, not the benefits of CSAPR as a substitute for CAIR. And the RIA indicates that 99 % or more of the alleged PM-2.5 health benefits occur in areas where PM-2.5 levels are already below the PM-2.5 standard. That is, the vast majority of the CSAPR health benefits will be in areas that already have air quality below the levels deemed necessary to protect public health and welfare, calling into question EPA's entire CSAPR benefits analysis.

In its comments on the proposed Transport Rule, Southern Company explained that this rule provides no demonstrable benefits over CAIR, and EPA failed to provide any substantive response to those comments. In an apparent effort to avoid the issue, EPA simply lumped Southern Company's comments on remedies and equivalent benefits in with its comments supporting an interstate trading program and generically responded to both sections of Southern's comments as follows:

> Thank you for your comments. EPA is finalizing the air quality assured trading remedy for the reasons explained in section VII.A of the preamble to the final Transport Rule. In section VII.J of the preamble to the final Transport Rule EPA explains why this remedy structure comports with the Court's opinion in the North Carolina decision. Section IV also describes in detail the legal authority and environmental basis for the transport rule.

U.S. Environmental Protection Agency Office of Air and Radiation, Transport Rule Primary Response to Comments, (June 2011) at 877. In essence, EPA ignores the substance of Southern's comment. This failure to respond only reinforces the point despite significant differences in emission levels state-to-state, CAIR and CSAPR result in similar overall emission reductions and air quality results.

In summary, CSAPR will increase costs, create significant volatility in the allowance markets, limit operational flexibility, and in some cases may be impossible to achieve, with little difference in the targeted air quality results as compared to CAIR. For all of the foregoing reasons, EPA should reconsider and stay CSAPR and leave CAIR in place pending its reconsideration and judicial review.

Attachment A

SOUTHERN COMPANY

CSAPR

Technical Corrections

9/29/2011

Table of Contents

1. Summary

On September 28, 2011 Southern Company (Southern) and its Operating Companies, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, held a conference call with Sam Napolitano, Jeb Stenhouse, and Brian Fisher of EPA. The purpose of the call was to discuss technical errors embedded in the final budgets and allocations of the Cross-State Air Pollution Rule. The information provided below contains more detail about these errors and/or asks questions to EPA. Southern urges EPA to correct the errors identified below and issue updated state budgets in a timely fashion.

2. Fuel Switching

Southern commented to EPA, that fuel switching should not be assumed for any of its plants in the year 2012. In its comments to EPA, Southern noted that as of August 2010, about two-thirds of it 2012 coal supply was under contract (see page 21 of Southern's comments on the proposed Transport Rule).

On the call, EPA explained that it made adjustments to fuel-switching assumptions where it had specific information about contract limitations (e.g., where commenters provided the contracts). Southern requests that EPA point us to somewhere in the record where the Agency lists which contracts/comments it found specific enough to warrant adjustments to fuel-switching assumptions. Southern also requests that EPA provide us with samples of the comments that were specific enough in the Agency's view to warrant imposing limitations.

3. Georgia Power

In the final rule, McDonough 1 is retired 4 months too early, as of 1/1/12. McDonough Unit 1 should not be retired until April 30, 2012 and its emissions should be included in the state budget for 2012.

- In the proposed rule, McDonough 1&2 were assumed to not be retired and were included uncontrolled in 2012 and controlled in 2014 (probably based that on an older version of the MPR). **<u>Southern provided the correct Multipollutant Rule dates in Attachment B of its comments.</u>**
- In NODA1, McDonough 1&2 continued to show up as uncontrolled in 2012 and controlled in 2014.

In the final rule, Mitchell 3 is converted to biomass as of 1/1/12 and its emissions appear to be excluded from the state budget determination. Mitchell Unit 3 should not be converted to biomass and its emissions should be included in the state budget for both 2012 and 2014.

- In the proposed rule, Mitchell was included as coal-fired; thus, Southern did not comment.
- **<u>In the NODA1, Southern noted on page 18 of its comments that the new NEEDS 4.10 incorrectly assumes Mitchell converts to biomass and that any conversion would occur well after the compliance date for the Transport Rule (earliest expected is late 2015).</u>**

- Even if EPA assumes Mitchell Unit 3 is converted to biomass at some point (late 2015 or later), it should not exclude its emissions in determining state budgets since a converted unit is still an affected unit.

In the final rule, several Multipollutant Rule dates were not corrected.

- In the proposed rule, Branch Units 1, 2, and 4, Yates Units 6&7, and Scherer Unit 1 were assumed to have SCR and FGD as of 1/1/2014. **Southern commented on these errors on page 25 of its comments and also provided the Multipollutant Rule dates in Attachment B.**

- In the NODA1, some changes to control configuration were made at Plant Scherer units, but Unit 1 was still incorrect. **Thus, Southern commented again on Scherer 1 on page 19 of its comments.** Branch and Yates dates were also still incorrect in NODA1, but since there were no control configuration changes at those plants between proposed rule and NODA1, Southern did not comment again.

The final IPM runs assume that total statewide fossil generation (MWh) drops significantly in Georgia about 18% between 2010 and 2012.

- The proposed rule IPM generation in Georgia was much closer to historical 2010 generation; thus, Southern did not comment.

- In NODA1, the IPM runs showed a ~20% drop in heat input from the state of Georgia. **Southern noted on page 18 of itscomments that this drop is not adequately explained.**

The final rule incorrectly switches Plants Branch, Yates, Kraft, and McIntosh to 0.6% sulfur coal in 2012.

- The proposed rule 2012 budget for Georgia was developed based on 2009 adjusted reported emissions. Thus, there were no fuel switches involved in setting the 2012 budget. **Southern still commented, however, on page 26 of its comments that there were several plants (Yates, Kraft, McIntosh) for which either the modeled base emission rates and/or permit limits for SO2 appeared to be unreasonably low. Southern also commented on page 21 of its comments that fuel switching is not feasible by 2012.**

- **In NODA1, Southern commented generally on page 16 of its comments that there were still mistakes in NEEDS4.10 SO2 emission rates (some units continued to be incorrectly designated to have NSPS limit).**

4. Gulf Power

4.1. Background

Gulf Power has three electric generating facilities in northwest Florida with a total generation of approximately 2100 MWs. The three plants are Plant Crist (near Pensacola), Plant Lansing Smith (near Panama City), and Plant Scholz (near Tallahassee). As a result of CSAPR, Gulf Power is subject only to the ozone season provisions. The allowance allocations are 56% below the actual NOx emissions in 2010 and approximately 2574 additional allowances would be needed. The EPA Remedy heat input is 31% below actual heat input for 2010 (@16.2 TBtus). The EPA Remedy average NOx rate is 36% below Gulf's actual for 2010.

4.2. Technical Comments

EPA's proposed NOx rate assumptions are unrealistic for several Gulf units:

- Crist Units 4 & 5 and Smith Unit 1 are projected in EPA Remedy Cases @ 0.18 lb/mmbtu. Here, each unit has an SNCR that is operational full time. Additionally, each are meeting design reduction of approximately 25%, Crist Units 4 & 5 are in the 0.36 to 0.40 range while Smith 1 is in the .29 range.
- Scholz Units 1 and 2 are projected in EPA Remedy Cases @ 0.245/.334 lb/mmbtu. Here the EPA rates appear to be based on 2009 CAMD data in which the units only ran 8 and 23 hours, respectively, but this is not quality data. These coal units have no controls and historically operate at approximately 0.58 lb/mmbtu.
- Gulf is replacing the SNCR on Crist Unit 6 with an SCR on 2012. EPA has the SCR listed as "dispatchable". Gulf believes this unit is non-dispatchable pursuant to state permit requirements.

EPA has underestimated heat input projections in the Policy Remedy Cases, with Gulf's projected heat input 31% below 2010 actual at approximately 16 TBtus. This is a value that is below any reported over last 20 years and only slightly above Gulf's need for voltage control (area protection).

Question regarding why Smith Combined Cycle Unit is not dispatched in EPA's model runs? This is Gulf's most efficient generating unit. 2010 dispatch ~ 2 TBtus.

Gulf projects a territorial load demand (2011 PSC Ten Years Site Plant) for 2012 @~6275 GWHs or about 60.2 TBtus which is about 41% higher than EPA's projected Remedy heat input for Gulf. Gulf would need to either purchase allowances or import power needs for ~ 2497 GWHs. Gulf is unaware if or how EPA considered transmission constraints to meet our area load demand for Summer 2012 Peak Season.

4.3. Additional items

Below are additional items that are attached in response to the EPA call on 9-28-11.

- Review if Gulf made comments on EPA’s NEEDS data base assumptions and send a copy to EPA: Gulf provided Southern Company with comments on NEEDS 3.02 and 4.1 database on ~ 9/17/2010 (database attached to this response)
- Review and supply EPA with Smith Combined Cycle Heat Rate. Review of the NEEDS database above notes Smith CCCT heat rate at 7274 btu/kwh. Gulf did not correct or comment that this value was incorrect in our NEEDS comments noted above. Research indicates the unit operated in the 7200 range until the 2010 outage. The current average heat rate for Smith CCCT is 6905 btu/kwh. (Gulf Summer Load Analysis attached to this response)
- Review EPA’s load curves (ongoing) as compared to Gulf’s Ten Year Site Plan (Schedule 4 of Gulf’s TYSP attached to this response)

Gulf Power Load Analysis for CSAPR

An analysis of the summer load demand in the 2011 Ten Year Site Plan was conducted to estimate what impact the reduced Heat Input projected in EPA's CSAPR Remedy Cases would have on Gulf's Load Demand.

	Schedule 4 2012 Forecast MW Demand	Schedule 4 2012 Forecast NEL GWH	kwh	btus *	mmbtu	tbtu
May	2393	1129	1129000000	1.08384E+13	10838400	10.8384
June	2581	1261	1261000000	1.21056E+13	12105600	12.1056
July	2642	1363	1363000000	1.30848E+13	13084800	13.0848
Aug	2624	1351	1351000000	1.29696E+13	12969600	12.9696
Sep	2482	1171	1171000000	1.12416E+13	11241600	11.2416
		6275	6275000000	6.024E+13	60240000	60.24

* using heat rate = 9,600 btu/kwh

		Gulf Power Ozone Season Heat Input (MMBtu)				
		Historical			Forecasted	
		2008	2009	2010	EPA Remedy 2012 (Forecasted)	EPA Remedy 2014 (Forecasted)
Delta MMBTU	**Delta GWH**	49,257,143	38,363,782	51,481,105	35,267,006	40,815,146
From EPA 2012						
24,972,994	2497.3	or ~41% GWH from outside of FL				

Schedule 4

Previous Year Actual and Two Year Forecast of Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2010 Actual		2011 Forecast		2012 Forecast	
	Peak Demand	NEL	Peak Demand	NEL	Peak Demand	NEL
Month	MW	GWH	MW	GWH	MW	GWH
January	2,553	1,106	2,296	1,005	2,371	1,039
February	2,144	955	2,083	841	2,226	894
March	1,934	851	1,821	871	1,892	902
April	1,488	803	1,897	859	1,966	889
May	2,219	1,070	2,320	1,096	2,393	1,129
June	2,419	1,244	2,526	1,230	2,581	1,261
July	2,525	1,325	2,592	1,331	2,642	1,363
August	2,458	1,282	2,574	1,319	2,625	1,351
September	2,300	1,139	2,424	1,143	2,482	1,171
October	1,881	891	2,227	1,006	2,288	1,035
November	1,574	796	1,836	870	1,892	896
December	2,314	1,057	2,092	957	2,152	982

6275

NOTE: Includes contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA)

EPA math = 35.24 TBTu

Plant Scholz NOx Rate Analysis
09/29/2011

In 2009, Scholz Unit 1 was fired on April 2, 2009 for a total of 8 hours to pressurize the boiler for a nitrogen cap. During this firing oil and coal was used but in quantities well below normal operation. As you can see from the tables below, 2009 was a very unusual year.

This data should not be used by EPA for CSAPR since:

1) Eight (8) hours of operation in one year is far too small of a data set.
2) This firing did not bring the unit on-line for normal operation.
3) Normal temperatures at the dilution probe may not have been obtained during this brief run.
4) The heat input during the eight hours was about 15% of what is typical at minimum load.
5) The operation rate during the eight hours was 15% of what would be acceptable for certification and RATA test runs which would need to be performed at least at minimum load.
6) Comparing the Scholz U1 NOx in 2009 to normal years, shows the 2009 year as very, very unusual.
7) Gulf recommends the 2007 CEM NOx rate of .584 lb/mmbtu be used as representative of emissions for Scholz 1 and 2. Please note that Scholz 1 and 2 have a common stack.

	NOx Rate Common	Hours of Operation 1	2
2007	0.584	8249	7885
2008	0.649	5904	5852
2009	0.632	8	323
2010	0.537	1950	1906

Attachment B

Evaluation of Compliance Options under the Cross-State Air Pollution Rule (CSAPR)

by Seth Schwartz, President, Energy Ventures Analysis, Inc.

1. EPA's method of establishing state emission budgets was based upon EPA's model of compliance costs, not based upon the environmental impact of state emissions on compliance with National Ambient Air Quality Standards (NAAQS)
    a. EPA determined which states would be regulated under CSAPR based upon whether its air quality modeling indicated that the state had a significant contribution[1] to nonattainment or interference with maintenance of the NAAQS at downwind monitors.
    b. Once a state was determined to have a significant contribution, the level of its annual emission budget was established by EPA based upon EPA's analysis of the cost-effectiveness of reducing emissions from each state.
        i. EPA first determined the "cost curve" for reducing emissions in each state from the baseline emissions projected by EPA without CSAPR.[2]
        ii. EPA next evaluated the impact of the combined emission reductions at different cost levels on the NAAQS levels at downwind monitors.[3] This was an evaluation of the combined reductions at all upwind states at a defined cost per ton of emission reductions, not an evaluation of the reduction of the contribution of each state to compliance with NAAQS.
        iii. EPA then defined the "significant cost threshold" to be a cost per ton at which the impact of increasing compliance costs, which resulted in further emissions reductions had "noticeably" less impact on NAAQS compliance.[4]
        iv. Based upon the "significant cost threshold" per ton of emissions reduction selected by EPA, EPA then assigned a "budget" of allowable emissions of each pollutant to each state.[5] The calculation of the budget for each state was based upon EPA's Integrated Planning Model ("IPM"),

[1] EPA's definition of a significant contribution is if the state's emissions contributed more than 1.0% of the NAAQS at any downwind monitor (Preamble to the Final Rule, Section V.D.1, page 133)
[2] Preamble, Section VI.A.2, page 178
[3] Preamble, Section VI.A.2, page 180
[4] Preamble, Section VI.A.2, page 181
[5] Preamble, Section VI.A.2, page 182

which presumes to calculate the emission and cost of emissions reductions for each state.

c. For SO_2 emissions reductions in 2012, the significant cost threshold for all states was selected to be $500 per ton of SO_2 removed from the baseline emissions. EPA selected this level for 2012 because "EPA believes that this threshold captures all emission reductions feasible by 2012".[6]
    i. While EPA states that it has "reasons" for concluding that "significant" cost reductions (i.e., reductions which can be achieved at a cost of $500 per ton of SO_2 removed from the "baseline" emission level) can be achieved by 2012, it only asserts that "reductions come from operating existing controls, installing combustion controls, fuel switching, and increased dispatch of lower-emitting generation which can be achieved by 2012".[7]
    ii. In fact, EPA provides no analysis of the emission rates by state in 2012 at cost reduction thresholds other than $500 per ton.
d. Further, EPA does not provide any analysis of whether lower SO_2 emission reductions at cost less than $500 per ton would still achieve the goal of resolving nonattainment and maintenance problems with the NAAQS for all states or any individual states in Group 2.
    i. EPA's air quality assessment tool projected that the SO_2 reduction at the $500 per ton cost threshold would resolve the nonattainment and maintenance problems for all of the areas to which the Group 2 states were linked.[8] As a result, EPA did not evaluate the impact of ***higher*** cost thresholds in the Group 2 states for 2014.
    ii. EPA never evaluated the impact of cost thresholds ***lower*** than $500 per ton for SO_2 in the Group 2 states on compliance with NAAQS.
e. The emission budget for each state in Group 2 was established at the same $500 per ton assumed cost threshold, regardless of whether the impact on compliance with NAAQS of any individual state in the group would be "resolved" at a lower cost threshold.

2. EPA's determination of state budgets was based solely on the economic analysis of its IPM model, which forecasts future electric power generation, emissions and cost of emission reductions.
    a. Because the state emission budgets were established based upon the IPM model's estimated emissions at a selected cost per ton of removal, rather than

[6] Preamble, VI.B.2, page 190
[7] Preamble, VI.B.3, page 193
[8] Preamble, VI.D.2, page 216

solely based upon the impact of a state's emissions upon compliance with NAAQS at downwind monitors, the amount of a state's emission budget is based on the accuracy of EPA's IPM model, not on the compliance with NAAQS.

   b. Any forecast of the future economics of a sector as large as the electric power sector is fraught with uncertainty. The level of detail required for EPA to set state emission budgets in this fashion is far beyond the capability of any model or agency. At a minimum, EPA's model requires the knowledge of the following factors, in the base year (2007) and in the future:
      i. Demand for electricity
      ii. The economics of generation for every electric generating unit ("EGU"), including:
         1. The cost of fuel (prices of natural gas, coal, oil, etc.)
         2. The fuel which can be used at each EGU, especially the type of coal and delivered price (including the mine price and transportation costs)
         3. The efficiency of each EGU
         4. The emission control technology employed at each EGU
         5. The economics of constructing new emissions control technologies at each EGU
         6. The emissions of SO_2 and NOx from each EGU
      iii. The level of generation (dispatch) and emissions at each EGU as a function of varying emission allowance prices
   c. As a result, any mistakes in the IPM model, as well as the inherent uncertainty of forecasting future generation, costs and emissions for the electric power industry create levels of state emission budgets which are not justified by EPA for compliance with NAAQS.
3. EPA's approach to allocating state budgets is fundamentally unfair, as it assigns lower emission budgets to states which have already reduced emissions or have emission reduction plans in place, regardless of whether further emission reductions are needed to resolve impacts on compliance with NAAQS at downwind monitors.
   a. In calculating the emissions by state which can be achieved at a cost threshold of \$500 per ton of SO_2 by 2012, EPA assigns much lower allowable emissions to states which have already instituted programs to reduce emission than states which have not done so.
      i. As a result, because Georgia Power has already invested in expensive SO_2 emissions control technology ("scrubbers") at many of its largest coal-fired power plants (Bowen, Wansley and Hammond), the State of Georgia

has been allocated much lower SO_2 emission budgets for 2012 (and 2014) than it would have received had it not yet made those investments.

ii. Further, EPA assumes that additional emission control investments which Georgia Power has planned will be in effect in the "base case" in 2012 and 2014 and thus occur at *no cost*, even though these emission reductions actually cost more than $500 per ton.
    1. By 2012, Georgia Power has planned to retire the Jack McDonough power plant and replace it with a new gas-fired plant as well
    2. By 2012, Georgia Power has constructed a new scrubber at the Scherer unit 3 power plant
    3. EPA assumes that the Yates units 6-7 and McIntosh 1 will have reduced emissions by switching to a very low-sulfur coal by 2012, which is not required and not planned by Georgia Power[9]

b. EPA has further reduced the State of Georgia's SO_2 emission budget for 2014 significantly because EPA assumes that large additional emission reductions will occur in the "base case" without CSAPR.
    i. The State of Georgia has been singled out for this adverse treatment by EPA in 2014. EPA has assigned the State of Georgia a budget of 95,231 tons of SO_2 in 2014, down 40% from a budget of 158,527 tons in 2012. Of the 6 other Group 2 states, 5 have the exact same SO_2 emissions budget for 2014 as for 2012.
    ii. EPA has reduced Georgia's 2014 SO_2 emission budget solely because Georgia Power is planning to make large investments in emissions control technology regardless of whether CSAPR is promulgated. Thus, Georgia is being punished for investing in emission controls. EPA has made the following assumptions in its IPM model base case:
        1. By 2014, Georgia Power has planned to construct new scrubbers at the Scherer units ~~1,~~ 2 and 4 power plants, which is correct. Scherer 1 scrubber will likely be completed in 2014, but is not required to operate until 12/31/2014 and will not be available 1/1/2014 as EPA assumes.
        2. By 2014, Georgia Power will construct new scrubbers at Harllee Branch units 1-4 and Yates 6 and 7, which is not correct. Georgia Power has not made this decision to build these scrubbers, and if it does, they will not be completed by 2014.

[9] EPA's IPM model incorrectly assumes that Yates 6-7 have a maximum emission limitation of 1.2 pounds SO_2 per million Btu, which requires the use of low-sulfur coal

iii. EPA has reduced the State of Georgia's emission budget for 2014 because these "other emissions reductions … would occur even in the baseline, (so) other sources within the state would be allowed to increase their emissions" if EPA did not reduce Georgia's SO_2 emission budget from 2012 to 2014.[10]

1. Under EPA's theory of allocating state budgets, Georgia Power should be allowed to increase emissions at its other power plants in 2014 if it reduces emissions at some of its coal-fired units. There is no evidence that increased emissions at Georgia's other units would result in significant contributions to NAAQS nonattainment or maintenance at downwind monitors, as EPA has already determined that the state emission budgets for Group 2 states in 2012 resolved their contributions to NAAQS compliance at downwind sites.
2. EPA's 2014 SO_2 emissions budget for Georgia reduces Georgia's budget for no purpose other than preventing Georgia from using emission reductions at some of its plants to offset emissions at other plants in the state.

4. EPA's IPM model has numerous flaws in its "base case", forecasting what emissions would be in the absence of CSAPR. There are flaws both in the assumption of the future emission rates of the EGUs as well as the economics of coal selection by the EGUs.
    a. EPA assumes that emission rates at existing plants will increase dramatically from their existing and historical emission rates, merely because EPA's IPM model assumes that these higher emission rates would be the action that would occur in the absence of CSAPR.
        i. In Georgia, EPA's IPM model assumes in the "base case" that the Harllee Branch, Kraft and Yates 2-5 units will use high-sulfur coal with 4.28 pounds SO_2 per million Btu in 2012.
            1. These units have never emitted that high of an SO2 emission rate over the course of a year and would not use this coal in the "base case" without CSAPR.
            2. The actual annual average SO_2 emission rates for Harllee Branch and Yates 2-5 units have been 1.76 – 2.31 pounds SO_2 per million Btu.
            3. The actual average annual average SO_2 emission rates for the Kraft units have been less than 1.60 pounds SO_2.

[10] Preamble, Section VI.D.2, page 232

b. By assuming unrealistically high emission rates in the "base case", EPA has created an artificially low cost of reducing emissions per ton of reduction (under \$500 per ton of SO_2).
    i. The larger the denominator (tons of SO_2 reduced), the lower the cost of reductions per ton.
    ii. Thus, EPA's model can force these plants to switch to a very low-sulfur coal which would be very high cost, yet show a cost per ton of reductions at less than the \$500 per ton threshold which it selected.

5. EPA's IPM model has fundamental flaws in the options which it assumes are available for compliance in 2012.
    a. EPA concedes that compliance mechanisms which involve post-combustion control installation are not feasible before 2014, but believes that SO_2 reductions will be available in 2012 from "operating existing controls, fuel switching and increased dispatch of lower-emitting generation".
        i. "Increased dispatch of lower-emitting generation" is a euphemism for reducing generation of coal-fired units and replacing it with generation from gas-fired units.
    b. EPA incorrectly concludes that power companies are not "operating existing controls" in its base case.
        i. EPA's model results assume that 25,000 MW of existing scrubbers at coal-fired plants are "induced to operate" by CSAPR in 2014 (meaning that, even though they exist or are being built, they would not operate if EPA did not promulgate CSAPR).[11]
        ii. The evidence is that "existing SO_2 controls" (i.e., scrubbers) are being operated at their maximum removal rates at virtually all scrubbers already.
            1. EPA's assumption that scrubbers will not be operated in the "base case" without CSAPR depends upon its assumptions in the IPM model that, in the absence of CAIR (which is assumed to be vacated) and CSAPR, power companies will stop operating scrubbers for economic reasons.
            2. However, due to over-compliance with the acid rain regulations and the vacatur of CAIR, the market price of SO_2 emission allowances under CAIR during 2010 fell to less than \$4 per ton from a high in late 2005 and early 2006 of \$1,600 per ton. The value of reducing SO_2 emissions in 2010 was minimal and far less than the cost of operating scrubbers.

[11] Regulatory Impact Analysis for the final Transport Rule, Table 7-11

3. If the logic and data in EPA's IPM model were correct, power companies would already have stopped operating all of the scrubbers which they did not have to operate in 2010.
4. Power companies actually operated existing scrubbers in 2010 at levels at or below the 2006 level in almost all cases.
    a. In Georgia, Georgia Power constructed a scrubber at Yates unit 1 to comply with acid rain regulations. In 2006, the Yates unit 1 emission rate was 0.18 pounds SO_2 per million Btu and was 0.12 pounds in 2010, despite lower market price of SO_2 emission allowances. EPA's IPM model assumes that the "base case" emission rate at Yates unit 1 will increase to 0.56 pounds SO_2 per mm Btu in 2012 without CSAPR, but will be reduced to 0.43 pounds due to CSAPR, which is unrealistic given the actual historical operation of this scrubber.

iii. Thus, the artificial emission reductions assumed in EPA's IPM model create "benefits" of emission reductions due to CSAPR, which will not occur; and the reductions will have no compliance cost (the existing scrubbers have already been built).

c. EPA has fundamentally misapplied the concept of "coal supply curves" to rely upon the availability and price of coal for compliance in 2012.

i. The coal supply curves were provided by WoodMackenzie (a consulting firm) in 2007, with projections as to the amount of steam coal which would be available for the market in future projected years 2012, 2015, 2020, 2030, and 2040.

ii. The ability to increase coal production predicted by the supply curves is not just a question of geology and mining costs, it also requires time to increase supply in response to increased demand.

1. The supply curves in the IPM model for production in 2012 were based upon having the time period from 2007 to 2012 to make the investment to increase supply by 2012.
2. The projections made in 2007 were never meant to predict the increase in coal supply which could occur in a period of 5 months between the date of EPA's final CSAPR rule in July 2011 and the compliance date of January 2012.
3. In the real world, there is little increase in supply which could occur between actual 2011 production rates and production in

2012 because of the time it takes to add supply capacity (permits, facilities, equipment and staffing).

iii. Further, there have been huge changes in coal production costs and coal prices for the US coal supply regions between 2007 and 2011. It is highly unlikely that WoodMackenzie would develop the same supply curves (including mining costs and prices) as it did 4 years ago. On average, cash production costs for US coal supply regions have increased significantly from 2007 to 2011.

1. In Central Appalachia, average cash costs have increased from \$42.26 per ton in the first quarter of 2007 to \$71.51 per ton in the second quarter of 2011, an increase of 69%.
2. In the Illinois Basin, average cash costs have increased from \$25.88 per ton in the first quarter of 2007 to \$34.01 per ton in the second quarter of 2011, an increase of 31%.
3. In the Powder River Basin, average cash costs have increased from \$7.37 per ton in the first quarter of 2007 to \$10.20 per ton in the second quarter of 2011, an increase of 38%.[12]

iv. Production costs for the low-sulfur coal regions have increased faster than the costs for the high-sulfur coal regions, so that the cost of reducing SO2 emissions by switching to lower-sulfur coals has increased significantly since 2007. The coal supply curves used by EPA in the IPM model are so far out of date as to be not representative of the compliance costs in 2012.

1. Because the emission allowance budgets for each state are based on the predicted emissions by EPA's IPM model at a cost of reductions (principally through coal switching) of \$500 per ton of SO2, since the coal cost models are far out of date, the state emission budgets do not reflect the emissions which can be achieved by switching to lower-sulfur coal.

d. EPA assumes that the power plants without scrubbers will switch to "low-sulfur" bituminous and "very low-sulfur" subbituminous coals which are not available in the market for compliance in 2012.

i. For the state of Georgia, EPA's IPM model assumes that every plant which does not have a scrubber will use the lowest-sulfur coal available in EPA's model.

[12] Average cash costs for public coal companies from the "US Coal Quarterly Financial Report" published by Energy Ventures Analysis, Inc.

1. Georgia Power's Harllee Branch, Kraft, McIntosh and Yates units 2-7 all use bituminous coal (the IPM model does not allow them to select subbituminous coal) and are all projected by EPA's IPM model to use Alabama bituminous coal with an emission rate of 0.95 pounds SO_2 per million Btu[13] for CSAPR compliance in 2012 (switching from a 4.28 pound SO_2 coal in the "base case" which these plants have not used).
2. Georgia Power's Scherer units 1, 2 and 4 all use subbituminous coal and are projected to switch from 0.70 pound SO_2 coal to 0.58 pound SO_2 Western subbituminous coal (Powder River Basin, or "PRB" coal).[14]

ii. Alabama bituminous coal with "low-sulfur" emission rates of 0.95 pounds SO_2 per million Btu is not available for Georgia Power to purchase to reduce emissions to this level.

1. The "supply curve" for 2012 coal production for Alabama coal in EPA's IPM model projects that there is a supply of up to 17.3 million tons of steam coal with sulfur grade "BB" (0.95 pounds SO_2 per million Btu), available at a price of up to $53.80 per ton (in 2007 dollars, which is about $58 per ton in 2011 dollars).
2. According to the Energy Information Administration, for calendar year 2009[15], only 18.8 million tons was produced in the entire state of Alabama, including all qualities of coal (metallurgical and steam) and all grades of sulfur content.
3. Of the total supply of Alabama coal in 2009, 8.0 million tons was exported to world markets as metallurgical coal, 1.0 million tons was metallurgical coal sold to domestic markets and 1.2 million tons was sold to domestic industrial markets. Only 8.3 million tons

[13] While EPA has not published the IPM model results for the coal used by each plant, the coal selection can be derived by the coal supply options provided for each plant, whether the coal used is bituminous, subbituminous or lignite, and the emission rates. The coals which these plants "select" for CSAPR compliance in 2012 in the IPM model is a bituminous coal with grade "BB", i.e., low-sulfur bituminous. Further, the SO_2 emission rate for this BB grade coal is "Cluster 1", with an emission rate of 0.95 pounds per million Btu. The only coal supply regions in Cluster 1 are Alabama and Colorado. The plants located in Georgia are in coal demand regions "GAR1 and GAR2". In the IPM model, these regions only have the transportation option to use bituminous eastern coals and western PRB coal, not western bituminous coal or imports. Thus, the only low-sulfur bituminous coal which the Georgia plants could be using for CSAPR compliance in 2012 is Alabama coal.

[14] This coal is grade "SA" in the IPM model, or "very low-sulfur" subbituminous.

[15] DOE/EIA, "Quarterly Coal Report, October – December 2010", Table 2

of steam coal was supplied to the entire domestic power industry.[16]

4. EPA's IPM model projects that Georgia Power's plants will use 165 trillion Btu of Alabama bituminous "low-sulfur" coal (about 6.6 million tons) in 2012 with an emission rate of 0.95 pounds SO_2[17], which is far more than the total amount of Alabama low-sulfur coal available in the market.
5. To the extent that this coal exists in the market, most of it is being sold in the metallurgical coal market and is not available for the domestic steam coal market. Low-sulfur coal produced in Alabama is being sold in the export metallurgical coal market at prices over $200 per ton FOB mine.
    a. The largest producer of Alabama coal is Walter Energy, a public company which produced 8.2 million tons of Alabama coal in 2011. Walter reports that its 3rd quarter 2011 expected sales price will be about $230 per ton and its cash costs will be about $120 per ton.[18]
6. By assuming that large amounts of low-sulfur Alabama coal will be available for Georgia plants to purchase at mine prices under $60 per ton (plus low transportation costs, since Alabama is close to Georgia), EPA has assumed a low cost of reducing emissions for the Georgia unscrubbed plants which is totally unrealistic.

iii. EPA assumes that all plants burning PRB subbituminous coal without scrubbers will switch from "low-sulfur" coal (0.94 pounds SO_2 per million Btu) to "very low-sulfur" PRB coal with 0.58 pounds SO_2 per million Btu at almost no additional cost.

1. EPA's IPM model results predict that the consumption of "very low-sulfur" subbituminous coal will be 156 million tons in the "base case" in 2012 and 255 million tons in the CSAPR case in 2012, *an increase of 99 million tons next year*[19]
2. EPA's model predicts that the total use of subbituminous coal will increase by 20 million tons in 2012 (increase from 314 million tons in the "base case" to 334 million tons in the CSAPR case), but use

[16] DOE/EIA, "Coal Distribution – Annual 2009"; this report was relied upon by EPA in the Regulatory Impact Analysis for CSAPR, chapter 7.
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of “high-sulfur” and “low-sulfur” subbituminous coal is predicted to fall by 79 million tons, replaced by “very low-sulfur” coal.

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4. My analysis of the potential increase in supply of the “very low-sulfur” PRB coal in 2012 is that a maximum of 10 million tons could be produced over the existing production in 2011, far less than the 99 million tons in the IPM model results.
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6. In the market place, the producers who produce the limited supply of “very low-sulfur” PRB coal have sharply increased the price for “very low-sulfur” coal (0.58 pounds SO_2 per million Btu) asking for a premium of $4.00 per ton of coal over a “low-sulfur” PRB product, for coal with 0.3 pounds per million Btu less than typical PRB coal.[21] To the extent that there will be some additional supply of “very low-sulfur” coal available to power companies affected by CSAPR in 2012, there will be a very large increased cost to purchase this coal. To the extent that Georgia Power’s Scherer units 1, 2 and 4 purchase this “very low-sulfur” PRB coal in 2012, it will cost Georgia Power an extra $34 million to buy the 8.6 million tons of coal which EPA projects these units will use in 2012.

iv. As discussed earlier in this report, it is my assessment that only low-sulfur Alabama coal is allowed to be delivered to Georgia plants in IPM’s model. However, to the extent that EPA’s IPM model is projecting that the unscrubbed plants in Georgia will use imported or western bituminous

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1. For imported coal, EPA's model does not "project" the price of imported coal to determine the price of using this coal to comply with CSAPR. Rather, EPA has merely assumed that imported coal will cost $30.81 per ton.[22] This assumption is absurdly low. The current market price for imported coal is over $110 per ton delivered to a U.S. port.
2. The IPM model shows "coal supply curves" which would allow the production of 109 million tons of Colorado coal[23] with a grade of "BA" or "BB" grade (low-sulfur bituminous) in 2012 at a price of $25.90 per ton (in 2007 dollars, which would be about $28 per ton in 2011 dollars).
3. The actual total production of Colorado coal in 2010 was only 25.2 million tons[24] and production in 2011 is on pace for the same level of output.
4. To the extent that increased supply of this coal would be available for purchase to comply with CSAPR in 2012, the market price for purchase in 2012 is $42 (for the CG region) and $47 (CU region) per ton FOB mine, not $28 per ton.[25]

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Evaluation of Compliance Options under the Cross-State Air Pollution Rule (CSAPR)

by Seth Schwartz, President, Energy Ventures Analysis, Inc.

1. EPA's method of establishing state emission budgets was based upon EPA's model of compliance costs, not based upon the environmental impact of state emissions on compliance with National Ambient Air Quality Standards (NAAQS)
    a. EPA determined which states would be regulated under CSAPR based upon whether its air quality modeling indicated that the state had a significant contribution[1] to nonattainment or interference with maintenance of the NAAQS at downwind monitors.
    b. Once a state was determined to have a significant contribution, the level of its annual emission budget was established by EPA based upon EPA's analysis of the cost-effectiveness of reducing emissions from each state.
        i. EPA first determined the "cost curve" for reducing emissions in each state from the baseline emissions projected by EPA without CSAPR.[2]
        ii. EPA next evaluated the impact of the combined emission reductions at different cost levels on the NAAQS levels at downwind monitors.[3] This was an evaluation of the combined reductions at all upwind states at a defined cost per ton of emission reductions, not an evaluation of the reduction of the contribution of each state to compliance with NAAQS.
        iii. EPA then defined the "significant cost threshold" to be a cost per ton at which the impact of increasing compliance costs, which resulted in further emissions reductions had "noticeably" less impact on NAAQS compliance.[4]
        iv. Based upon the "significant cost threshold" per ton of emissions reduction selected by EPA, EPA then assigned a "budget" of allowable emissions of each pollutant to each state.[5] The calculation of the budget for each state was based upon EPA's Integrated Planning Model ("IPM"),

[1] EPA's definition of a significant contribution is if the state's emissions contributed more than 1.0% of the NAAQS at any downwind monitor (Preamble to the Final Rule, Section V.D.1, page 133)
[2] Preamble, Section VI.A.2, page 178
[3] Preamble, Section VI.A.2, page 180
[4] Preamble, Section VI.A.2, page 181
[5] Preamble, Section VI.A.2, page 182

which presumes to calculate the emission and cost of emissions reductions for each state.

c. For SO_2 emissions reductions in 2012, the significant cost threshold for all states was selected to be \$500 per ton of SO_2 removed from the baseline emissions. EPA selected this level for 2012 because "EPA believes that this threshold captures all emission reductions feasible by 2012".[6]

    i. While EPA states that it has "reasons" for concluding that "significant" cost reductions (i.e., reductions which can be achieved at a cost of \$500 per ton of SO_2 removed from the "baseline" emission level) can be achieved by 2012, it only asserts that "reductions come from operating existing controls, installing combustion controls, fuel switching, and increased dispatch of lower-emitting generation which can be achieved by 2012".[7]

    ii. In fact, EPA provides no analysis of the emission rates by state in 2012 at cost reduction thresholds other than \$500 per ton.

d. Further, EPA does not provide any analysis of whether lower SO_2 emission reductions at cost less than \$500 per ton would still achieve the goal of resolving nonattainment and maintenance problems with the NAAQS for all states or any individual states in Group 2.

    i. EPA's air quality assessment tool projected that the SO_2 reduction at the \$500 per ton cost threshold would resolve the nonattainment and maintenance problems for all of the areas to which the Group 2 states were linked.[8] As a result, EPA did not evaluate the impact of <u>*higher*</u> cost thresholds in the Group 2 states for 2014.

    ii. EPA never evaluated the impact of cost thresholds <u>*lower*</u> than \$500 per ton for SO_2 in the Group 2 states on compliance with NAAQS.

e. The emission budget for each state in Group 2 was established at the same \$500 per ton assumed cost threshold, regardless of whether the impact on compliance with NAAQS of any individual state in the group would be "resolved" at a lower cost threshold.

2. EPA's determination of state budgets was based solely on the economic analysis of its IPM model, which forecasts future electric power generation, emissions and cost of emission reductions.

    a. Because the state emission budgets were established based upon the IPM model's estimated emissions at a selected cost per ton of removal, rather than

[6] Preamble, VI.B.2, page 190
[7] Preamble, VI.B.3, page 193
[8] Preamble, VI.D.2, page 216

solely based upon the impact of a state's emissions upon compliance with NAAQS at downwind monitors, the amount of a state's emission budget is based on the accuracy of EPA's IPM model, not on the compliance with NAAQS.

b. Any forecast of the future economics of a sector as large as the electric power sector is fraught with uncertainty. The level of detail required for EPA to set state emission budgets in this fashion is far beyond the capability of any model or agency. At a minimum, EPA's model requires the knowledge of the following factors, in the base year (2007) and in the future:
    i. Demand for electricity
    ii. The economics of generation for every electric generating unit ("EGU"), including:
        1. The cost of fuel (prices of natural gas, coal, oil, etc.)
        2. The fuel which can be used at each EGU, especially the type of coal and delivered price (including the mine price and transportation costs)
        3. The efficiency of each EGU
        4. The emission control technology employed at each EGU
        5. The economics of constructing new emissions control technologies at each EGU
        6. The emissions of SO_2 and NOx from each EGU
    iii. The level of generation (dispatch) and emissions at each EGU as a function of varying emission allowance prices

c. As a result, any mistakes in the IPM model, as well as the inherent uncertainty of forecasting future generation, costs and emissions for the electric power industry create levels of state emission budgets which are not justified by EPA for compliance with NAAQS.

3. EPA's approach to allocating state budgets is fundamentally unfair, as it assigns lower emission budgets to states which have already reduced emissions or have emission reduction plans in place, regardless of whether further emission reductions are needed to resolve impacts on compliance with NAAQS at downwind monitors.
    a. In calculating the emissions by state which can be achieved at a cost threshold of $500 per ton of SO_2 by 2012, EPA assigns much lower allowable emissions to states which have already instituted programs to reduce emission than states which have not done so.
        i. As a result, because Georgia Power has already invested in expensive SO_2 emissions control technology ("scrubbers") at many of its largest coal-fired power plants (Bowen, Wansley and Hammond), the State of Georgia

has been allocated much lower SO_2 emission budgets for 2012 (and 2014) than it would have received had it not yet made those investments.

ii. Further, EPA assumes that additional emission control investments which Georgia Power has planned will be in effect in the "base case" in 2012 and 2014 and thus occur at *no cost*, even though these emission reductions actually cost more than $500 per ton.

1. By 2012, Georgia Power has planned to retire the Jack McDonough power plant and replace it with a new gas-fired plant as well
2. By 2012, Georgia Power has constructed a new scrubber at the Scherer unit 3 power plant
3. EPA assumes that the Yates units 6-7 and McIntosh 1 will have reduced emissions by switching to a very low-sulfur coal by 2012, which is not required and not planned by Georgia Power[9]

b. EPA has further reduced the State of Georgia's SO_2 emission budget for 2014 significantly because EPA assumes that large additional emission reductions will occur in the "base case" without CSAPR.

i. The State of Georgia has been singled out for this adverse treatment by EPA in 2014. EPA has assigned the State of Georgia a budget of 95,231 tons of SO_2 in 2014, down 40% from a budget of 158,527 tons in 2012. Of the 6 other Group 2 states, 5 have the exact same SO_2 emissions budget for 2014 as for 2012.

ii. EPA has reduced Georgia's 2014 SO_2 emission budget solely because Georgia Power is planning to make large investments in emissions control technology regardless of whether CSAPR is promulgated. Thus, Georgia is being punished for investing in emission controls. EPA has made the following assumptions in its IPM model base case:

1. By 2014, Georgia Power has planned to construct new scrubbers at the Scherer units 2 and 4 power plants, which is correct. Scherer 1 scrubber will likely be completed in 2014, but is not required to operate until 12/31/2014 and will not be available 1/1/2014 as EPA assumes.
2. By 2014, Georgia Power will construct new scrubbers at Harllee Branch units 1-4 and Yates 6 and 7, which is not correct. Georgia Power has not made this decision to build these scrubbers, and if it does, they will not be completed by 2014.

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[9] EPA's IPM model incorrectly assumes that Yates 6-7 have a maximum emission limitation of 1.2 pounds SO_2 per million Btu, which requires the use of low-sulfur coal

iii. EPA has reduced the State of Georgia's emission budget for 2014 because these "other emissions reductions … would occur even in the baseline, (so) other sources within the state would be allowed to increase their emissions" if EPA did not reduce Georgia's SO_2 emission budget from 2012 to 2014.[10]

1. Under EPA's theory of allocating state budgets, Georgia Power should be allowed to increase emissions at its other power plants in 2014 if it reduces emissions at some of its coal-fired units. There is no evidence that increased emissions at Georgia's other units would result in significant contributions to NAAQS nonattainment or maintenance at downwind monitors, as EPA has already determined that the state emission budgets for Group 2 states in 2012 resolved their contributions to NAAQS compliance at downwind sites.
2. EPA's 2014 SO_2 emissions budget for Georgia reduces Georgia's budget for no purpose other than preventing Georgia from using emission reductions at some of its plants to offset emissions at other plants in the state.

4. EPA's IPM model has numerous flaws in its "base case", forecasting what emissions would be in the absence of CSAPR. There are flaws both in the assumption of the future emission rates of the EGUs as well as the economics of coal selection by the EGUs.

a. EPA assumes that emission rates at existing plants will increase dramatically from their existing and historical emission rates, merely because EPA's IPM model assumes that these higher emission rates would be the action that would occur in the absence of CSAPR.

i. In Georgia, EPA's IPM model assumes in the "base case" that the Harllee Branch, Kraft and Yates 2-5 units will use high-sulfur coal with 4.28 pounds SO_2 per million Btu in 2012.

1. These units have not burned coal with this level of sulfur content in almost twenty years and would not use this coal in the "base case" without CSAPR.
2. The actual annual average SO_2 emission rates for Harllee Branch and Yates 2-5 units have been 1.76 – 2.31 pounds SO_2 per million Btu.
3. The actual average annual average SO_2 emission rates for the Kraft units have been less than 1.60 pounds SO_2.

[10] Preamble, Section VI.D.2, page 232

b. By assuming unrealistically high emission rates in the "base case", EPA has created an artificially low cost of reducing emissions per ton of reduction (under $500 per ton of SO_2).
    i. The larger the denominator (tons of SO_2 reduced), the lower the cost of reductions per ton.
    ii. Thus, EPA's model can force these plants to switch to a very low-sulfur coal which would be very high cost, yet show a cost per ton of reductions at less than the $500 per ton threshold which it selected.

5. EPA's IPM model has fundamental flaws in the options which it assumes are available for compliance in 2012.
    a. EPA concedes that compliance mechanisms which involve post-combustion control installation are not feasible before 2014, but believes that SO_2 reductions will be available in 2012 from "operating existing controls, fuel switching and increased dispatch of lower-emitting generation".
        i. "Increased dispatch of lower-emitting generation" is a euphemism for reducing generation of coal-fired units and replacing it with generation from gas-fired units.
    b. EPA incorrectly concludes that power companies are not "operating existing controls" in its base case.
        i. EPA's model results assume that 25,000 MW of existing scrubbers at coal-fired plants are "induced to operate" by CSAPR in 2014 (meaning that, even though they exist or are being built, they would not operate if EPA did not promulgate CSAPR).[11]
        ii. The evidence is that "existing SO_2 controls" (i.e., scrubbers) are being operated at their maximum removal rates at virtually all scrubbers already.
            1. EPA's assumption that scrubbers will not be operated in the "base case" without CSAPR depends upon its assumptions in the IPM model that, in the absence of CAIR (which is assumed to be vacated) and CSAPR, power companies will stop operating scrubbers for economic reasons.
            2. However, due to over-compliance with the acid rain regulations and the vacatur of CAIR, the market price of SO_2 emission allowances under CAIR during 2010 fell to less than $4 per ton from a high in late 2005 and early 2006 of $1,600 per ton. The cost of reducing SO_2 emissions in 2010 was minimal and far less than the cost of operating scrubbers.

[11] Regulatory Impact Analysis for the final Transport Rule, Table 7-11

3. If the logic and data in EPA's IPM model were correct, power companies would already have stopped operating all of the scrubbers which they did not have to operate in 2010.
4. Power companies actually operated existing scrubbers in 2010 at levels at or below the 2006 level in almost all cases.
    a. In Georgia, Georgia Power constructed a scrubber at Yates unit 1 to comply with acid rain regulations. In 2006, the Yates unit 1 emission rate was 0.18 pounds SO_2 per million Btu and was 0.12 pounds in 2010, despite lower market price of SO_2 emission allowances. EPA's IPM model assumes that the "base case" emission rate at Yates unit 1 will increase to 0.56 pounds SO_2 per mm Btu in 2012 without CSAPR, but will be reduced to 0.43 pounds due to CSAPR, which is unrealistic given the actual historical operation of this scrubber.

iii. Thus, the artificial emission reductions assumed in EPA's IPM model create "benefits" of emission reductions due to CSAPR, which will not occur; and the reductions will have no compliance cost (the existing scrubbers have already been built).

c. EPA has fundamentally misapplied the concept of "coal supply curves" to rely upon the availability and price of coal for compliance in 2012.

i. The coal supply curves were provided by WoodMackenzie (a consulting firm) in 2007, with projections as to the amount of steam coal which would be available for the market in future projected years 2012, 2015, 2020, 2030, and 2040.

ii. The ability to increase coal production predicted by the supply curves is not just a question of geology and mining costs, it also requires time to increase supply in response to increased demand.

1. The supply curves in the IPM model for production in 2012 were based upon having the time period from 2007 to 2012 to make the investment to increase supply by 2012.
2. The projections made in 2007 were never meant to predict the increase in coal supply which could occur in a period of 5 months between the date of EPA's final CSAPR rule in July 2011 and the compliance date of January 2012.
3. In the real world, there is little increase in supply which could occur between actual 2011 production rates and production in

2012 because of the time it takes to add supply capacity (permits, facilities, equipment and staffing).

iii. Further, there have been huge changes in coal production costs and coal prices for the US coal supply regions between 2007 and 2011. It is highly unlikely that WoodMackenzie would develop the same supply curves (including mining costs and prices) as it did 4 years ago. On average, cash production costs for US coal supply regions have increased significantly from 2007 to 2011.

1. In Central Appalachia, average cash costs have increased from $42.26 per ton in the first quarter of 2007 to $71.51 per ton in the second quarter of 2011, an increase of 69%.
2. In the Illinois Basin, average cash costs have increased from $25.88 per ton in the first quarter of 2007 to $34.01 per ton in the second quarter of 2011, an increase of 31%.
3. In the Powder River Basin, average cash costs have increased from $7.37 per ton in the first quarter of 2007 to $10.20 per ton in the second quarter of 2011, an increase of 38%.[12]

iv. Production costs for the low-sulfur coal regions have increased faster than the costs for the high-sulfur coal regions, so that the cost of reducing SO2 emissions by switching to lower-sulfur coals has increased significantly since 2007. The coal supply curves used by EPA in the IPM model are so far out of date as to be not representative of the compliance costs in 2012.

1. Because the emission allowance budgets for each state are based on the predicted emissions by EPA's IPM model at a cost of reductions (principally through coal switching) of $500 per ton of SO2, since the coal cost models are far out of date, the state emission budgets do not reflect the emissions which can be achieved by switching to lower-sulfur coal.

d. EPA assumes that the power plants without scrubbers will switch to "low-sulfur" bituminous and "very low-sulfur" subbituminous coals which are not available in the market for compliance in 2012.

i. For the state of Georgia, EPA's IPM model assumes that every plant which does not have a scrubber will use the lowest-sulfur coal available in EPA's model.

[12] Average cash costs for public coal companies from the "US Coal Quarterly Financial Report" published by Energy Ventures Analysis, Inc.

1. Georgia Power's Harllee Branch, Kraft, McIntosh and Yates units 2-7 all use bituminous coal (the IPM model does not allow them to select subbituminous coal) and are all projected by EPA's IPM model to use Alabama bituminous coal with an emission rate of 0.95 pounds SO_2 per million Btu[13] for CSAPR compliance in 2012 (switching from a 4.28 pound SO_2 coal in the "base case" which these plants have not used).
2. Georgia Power's Scherer units 1, 2 and 4 all use subbituminous coal and are projected to switch from 0.70 pound SO_2 coal to 0.58 pound SO_2 Western subbituminous coal (Powder River Basin, or "PRB" coal).[14]

ii. Alabama bituminous coal with "low-sulfur" emission rates of 0.95 pounds SO_2 per million Btu is not available for Georgia Power to purchase to reduce emissions to this level.

1. The "supply curve" for 2012 coal production for Alabama coal in EPA's IPM model projects that there is a supply of up to 17.3 million tons of steam coal with sulfur grade "BB" (0.95 pounds SO_2 per million Btu), available at a price of up to $53.80 per ton (in 2007 dollars, which is about $58 per ton in 2011 dollars).
2. According to the Energy Information Administration, for calendar year 2009[15], only 18.8 million tons was produced in the entire state of Alabama, including all qualities of coal (metallurgical and steam) and all grades of sulfur content.
3. Of the total supply of Alabama coal in 2009, 8.0 million tons was exported to world markets as metallurgical coal, 1.0 million tons was metallurgical coal sold to domestic markets and 1.2 million tons was sold to domestic industrial markets. Only 8.3 million tons

[13] While EPA has not published the IPM model results for the coal used by each plant, the coal selection can be derived by the coal supply options provided for each plant, whether the coal used is bituminous, subbituminous or lignite, and the emission rates. The coals which these plants "select" for CSAPR compliance in 2012 in the IPM model is a bituminous coal with grade "BB", i.e., low-sulfur bituminous. Further, the SO_2 emission rate for this BB grade coal is "Cluster 1", with an emission rate of 0.95 pounds per million Btu. The only coal supply regions in Cluster 1 are Alabama and Colorado. The plants located in Georgia are in coal demand regions "GAR1 and GAR2". In the IPM model, these regions only have the transportation option to use bituminous eastern coals and western PRB coal, not western bituminous coal or imports. Thus, the only low-sulfur bituminous coal which the Georgia plants could be using for CSAPR compliance in 2012 is Alabama coal.

[14] This coal is grade "SA" in the IPM model, or "very low-sulfur" subbituminous.

[15] DOE/EIA, "Quarterly Coal Report, October – December 2010", Table 2

of steam coal was supplied to the entire domestic power industry.[16]

4. EPA's IPM model projects that Georgia Power's plants will use 165 trillion Btu of Alabama bituminous "low-sulfur" coal (about 6.6 million tons) in 2012 with an emission rate of 0.95 pounds SO_2[17], which is far more than the total amount of Alabama low-sulfur coal available in the market.
5. To the extent that this coal exists in the market, most of it is being sold in the metallurgical coal market and is not available for the domestic steam coal market. Low-sulfur coal produced in Alabama is being sold in the export metallurgical coal market at prices over $200 per ton FOB mine.
   a. The largest producer of Alabama coal is Walter Energy, a public company which produced 8.2 million tons of Alabama coal in 2011. Walter reports that its 3rd quarter 2011 expected sales price will be about $230 per ton and its cash costs will be about $120 per ton.[18]
6. By assuming that large amounts of low-sulfur Alabama coal will be available for Georgia plants to purchase at mine prices under $60 per ton (plus low transportation costs, since Alabama is close to Georgia), EPA has assumed a low cost of reducing emissions for the Georgia unscrubbed plants which is totally unrealistic.

iii. EPA assumes that all plants burning PRB subbituminous coal without scrubbers will switch from "low-sulfur" coal (0.94 pounds SO_2 per million Btu) to "very low-sulfur" PRB coal with 0.58 pounds SO_2 per million Btu at almost no additional cost.

1. EPA's IPM model results predict that the consumption of "very low-sulfur" subbituminous coal will be 156 million tons in the "base case" in 2012 and 255 million tons in the CSAPR case in 2012, *an increase of 99 million tons next year*[19]
2. EPA's model predicts that the total use of subbituminous coal will increase by 20 million tons in 2012 (increase from 314 million tons in the "base case" to 334 million tons in the CSAPR case), but use

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