Docket ID No. EPA-HQ-OAR-2009-0491-3773.1

COMMENTS OF THE UTILITY AIR REGULATORY GROUP

on the

NOTICE OF DATA AVAILABILITY SUPPORTING THE PROPOSED FEDERAL IMPLEMENTATION PLANS TO REDUCE INTERSTATE TRANSPORT OF FINE PARTICULATE MATTER AND OZONE

75 Fed. Reg. 53613 (Sept. 1, 2010); Docket ID No. EPA-HQ-OAR-2009-0491

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TABLE OF CONTENTS

I. Introduction 1

II. The Comment Period on the NODA Is Inadequate To Allow for Adequate Public Review of the Extensive Material Associated with It. 4

III. Despite the Quantity of New Information Added to the Docket Pursuant to the NODA, EPA Has Failed To Provide Data Necessary To Allow Meaningful Comment on That Information 5

IV. EPA's Decision To Base 2014 SO2 Allowance Allocations for Units in Group 1 States on the Same State-Level Emission Caps Used in the PTR -- Even Though Revised Data and an Updated Modeling Tool Were Available -- Is Arbitrary and Unjustified 10

V. Several of the Revisions to NEEDS and IPM that Are Reflected in the NODA Are Inappropriate or Inadequately Explained. 13

- A. EPA's Upward Adjustment of Its Assumption Regarding FGD Maximum Removal Efficiency Is Unjustified and Inaccurate. 13
- B. Units with Generating Capacity Less than 100 MW Cannot Properly Be Assumed To Be Candidates for Installation of FGD or SCR. 15
- C. EPA May Well Be Understating SCR Capital Costs 16
- D. EPA's Revised NEEDS Database and IPM Platform Still Contain Numerous Errors and Have Introduced Additional Inaccurate Assumptions 17

VI. In Making the Changes Represented in the NODA, EPA Continues To Ignore the Effects of CAIR and Local Controls. 21

- A. EPA Should Have Considered the Effects of CAIR 22
- B. EPA Should Have Considered the Effects of Local Controls 23

VII. The Availability of NEEDS v.4.10 and IPM v.4.10 and the Central Role These Items Play in the Structure of EPA's PTR Warrant a New or Supplemental Proposed Rule Based on the Results of the New Data and Modeling. 24

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I. Introduction

On September 1, 2010, the U.S. Environmental Protection Agency ("EPA" or the "Agency") published its Notice of Data Availability Supporting Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone ("NODA"). 75 Fed. Reg. 53613 (Sept. 1, 2010). The NODA supplements EPA's Proposed Air Pollution Transport Rule ("Proposed Transport Rule" or "PTR"), published in the Federal Register on August 2, 2010, which was the subject of a 60-day public comment period that ended on October 1, 2010. 75 Fed. Reg. 45210 (Aug. 2, 2010). The Proposed Transport Rule is intended to replace the Clean Air Interstate Rule ("CAIR"), which EPA promulgated in 2005 and the U.S. Court of Appeals for the D.C. Circuit held to be "fundamentally flawed," initially vacated and remanded to the Agency in 2008, and then allowed to remain in place pending completion of EPA's remand rulemaking. *See North Carolina v. EPA*, 531 F.3d 896, 929 (D.C. Cir. 2008), *modified on petitions for rehearing*, 550 F.3d 1176 (D.C. Cir. 2008). Like CAIR, the Proposed Transport Rule primarily addresses emissions from electric generating units ("EGUs") and is based on EPA's interpretation and application of section 110(a)(2)(D)(i)(I) of the Clean Air Act ("CAA" or "Act"), which requires, in relevant part, that each state's plan for attaining the national ambient air quality standards ("NAAQS") "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]."

The Utility Air Regulatory Group ("UARG") submits the following comments on the NODA. UARG is a voluntary, not-for-profit group of electric utilities, other electric generating companies, and national trade associations. UARG's purpose is to participate on behalf of its members collectively in EPA rulemakings under the CAA and other proceedings that affect the interests of electric generators and in related litigation. Because the Proposed Transport Rule specifically -- and exclusively -- targets nitrogen oxide ("NOx") and sulfur dioxide ("SO_2") emissions from EGUs for regulation, UARG and its members have a compelling interest in the present proceeding. These comments supplement comments that UARG submitted on the PTR on October 1, 2010, Docket ID No. EPA-HQ-OAR-2009-0491-2756.1 ("UARG's PTR Comments"), which are incorporated herein by reference.

The NODA announces EPA's placement in the docket of this rulemaking several new documents and computer runs that bear directly on the PTR. For example, the NODA announces the placement in the docket of information on a new version of the Integrated Planning Model ("IPM v4.10") that EPA is now using in the rulemaking on the Transport Rule; modeling results from the use of that new version; new emission inventory information; and new information on key cost and other assumptions to be used in EPA's rulemaking analyses. The new information adds hundreds of pages of documentation to the docket for this rulemaking. The NODA provides a 45-day comment period, until October 15, 2010, on the new information but states, without explanation, that EPA will not extend the comment period on the Proposed Transport Rule beyond the October 1, 2010 comment deadline.

UARG reiterates its objection, made in UARG's comments on the PTR, that Agency decisions have made participation in this rulemaking unreasonably and unnecessarily difficult. The information released pursuant to the NODA amounts to a substantially revised set of new data that provides at least a potential basis for changing virtually every aspect of the PTR. As UARG explained in its comments on the PTR, the comment period on that lengthy and complex proposed rule was itself inadequate, and EPA's decision to maintain two separate but largely overlapping periods for public comments -- one on the PTR and the information posted in the docket contemporaneously with it, and another, ending only two weeks after the PTR comment deadline, on the information released pursuant to the NODA -- has made it extraordinarily challenging to provide comprehensive comments on both the PTR and the NODA. On September 10, 2010, EPA denied UARG's August 19, 2010 request for an extension of the comment period on the PTR, and on October 5, 2010, the Agency denied UARG's September 10, 2010 request for a comment deadline extension for the NODA as well as for the PTR itself.[1] In light of the significant differences between the data on which EPA based (or says it based) the PTR and the data EPA released later pursuant to the NODA, EPA should withdraw the PTR, revise the PTR using the NODA data or whatever other data EPA may now deem most appropriate -- while addressing as well the many other deficiencies discussed in UARG's comments on the PTR and the present comments -- and publish a complete, properly supported proposal for public comment with an adequate comment period.

[1] UARG incorporates its August 19, 2010 and September 10, 2010 letters herein by reference.

II. The Comment Period on the NODA Is Inadequate To Allow for Adequate Public Review of the Extensive Material Associated with It.

As discussed above, EPA published the NODA midway through the inadequate public comment period on the PTR and denied UARG's requests for extensions of the comment periods on the PTR and the NODA. The NODA represents the addition of an extensive amount of new material to the docket for this rulemaking. For example, the new "Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model" ("Base Case v.4.10 Documentation") alone is 487 pages long and includes references to several new or revised databases. *See* EPA, "Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model" (Aug. 2010), Docket ID No. EPA-HQ-OAR-2009-0491-0309, *available at* http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html. Despite this large quantity of new information, the NODA provides only an additional 14 days for public comment beyond the comment deadline that UARG and other members of the public were required to meet for the PTR. This does not allow enough time for a comprehensive review of the new material provided, much less enough time to analyze the material, determine its implications for the underlying rule, and develop and submit complete comments.

The substantial impact of the NODA on the Proposed Transport Rule was apparent in recent comments by EPA representatives. During an EPA webinar held on September 22, 2010, in response to a question regarding which aspects of the PTR would be affected by the NODA, a representative of EPA's Clean Air Markets Division indicated that the information contained in the NODA would affect, among other things, EPA's "significant contribution" analysis, the creation and evaluation of the "cost curves" in EPA's multi-factor analysis for determining emission reduction obligations under the PTR, and the cost-effectiveness "breakpoints" for emission controls that EPA will select based on the cost curves and the multi-factor analysis.

This EPA representative acknowledged that the NODA may result in changes in EPA's determinations of which states are regulated under the Transport Rule, which states will be classified as group 1 rather than as group 2 states with respect to additional SO_2 emission control obligations in the second phase of the program, the emission budgets to which regulated states will be subject, and unit-level allowance allocations. These matters are far from tangential to EPA's development of the Transport Rule. To the contrary, they go to the very heart of the rulemaking. Yet, EPA provided only 14 days for public comment on the NODA beyond the comment period on the PTR.

Equally important, as discussed below, EPA has unreasonably withheld information necessary to allow UARG, members of UARG, other members of the public, and states to develop and provide meaningful and comprehensive comments on the NODA and on the Proposed Transport Rule itself. The following sections of these comments address new and continuing inadequacies and omissions in the record that UARG urges EPA to correct before the Agency continues with this rulemaking.

III. Despite the Quantity of New Information Added to the Docket Pursuant to the NODA, EPA Has Failed To Provide Data Necessary To Allow Meaningful Comment on That Information.

The problems associated with the unreasonably abbreviated period EPA has provided for comment on the voluminous and complex information issued pursuant to the NODA are exacerbated by EPA's failure to provide much of the information necessary to evaluate and meaningfully comment on the NODA. The docket omits much of the information that is necessary to properly evaluate the nature and extent of the changes that are likely to the PTR based on the addition to the docket of the data listed in the NODA.

In support of the PTR, EPA provided in the docket the results of 48 IPM runs. These runs provided the public at least some basis for evaluating and commenting on the various steps in EPA's process of developing unit-specific allowance allocations. In contrast, in support of the NODA, EPA provided the results of only eight IPM runs. Of these eight runs, four relate to an entirely new alternative proposal based on the Energy Information Administration's ("EIA") Annual Energy Outlook 2010 natural gas resource assumptions -- leaving only four IPM runs that constitute a repeat of runs used to support the PTR. The paucity of IPM runs that EPA has provided with the NODA, using the revised National Electric Energy Data System ("NEEDS") inventory and IPM v.4.10 frustrates the public's ability to comment knowledgeably on the effects on the PTR of the updated NEEDS database and IPM platform. *See* section VII *infra*. Despite EPA's limited use of the revised NEEDS inventory and IPM model in the allowance allocation step of its analysis,[2] EPA still has not provided the IPM runs necessary for electric generating companies and others, including states, to understand and comment knowledgeably on the impact of the NODA on statewide emission budgets and unit-specific allocations.

In addition to failing to provide many critical updated IPM runs using the NODA information, EPA has failed to provide key summary tables that it *did* provide in conjunction with the PTR. The key summary tables provided in support of the PTR include the "Allocation Table - Technical Support Document for the Transport Rule - State Budgets, Unit Allocations, and Unit Emission Rates" (EPA-HQ-OAR-2009-0491-0057.1) and the "Detailed Unit-Level Data for State-Budgets, Unit Allocations, and Unit Emission Rates" (EPA-HQ-OAR-2009-0491-

[2] UARG notes that, as it states in its comments on the PTR, EPA lacks authority under the CAA to impose unit-specific allowance allocations because the CAA "left to the states 'the power to [initially] determine *which sources* would be burdened by regulation and to *what extent*.'" *Michigan v. EPA*, 213 F.3d 663, 686 (D.C. Cir. 2001) (quoting *Union Elec. Co. v. EPA*, 427 U.S. 246, 269 (1976)) (alteration and emphases in original); *see also Virginia v. EPA*, 108 F.3d 1397, 1408 (D.C. Cir. 1997) (same). *See* UARG's PTR Comments at 19-27 (discussing the ways in which the PTR upsets the statutorily established relationship between the federal government and the states with respect to development of plans to address interstate pollution control under the CAA).

0074.1). In the PTR, these tables provided important guidance regarding a unit's allowance allocations under the PTR and provided electric generating companies at least some ability to evaluate the accuracy of EPA's assumptions (or apparent assumptions) with respect to their individual units. For reasons that UARG explained in its comments on the PTR, EPA's calculation of allowance allocations in the PTR was hardly a model of clarity. But EPA's failure to provide with the NODA tables comparable to the above-described PTR tables leaves UARG members and other electric utilities and electric generating companies even further in the dark about what their unit allowance allocations will be, based on the outcome of EPA's 2012 allowance allocation determinations using the updated NEEDS database and the updated IPM platform.

Perhaps the single most important file EPA did not provide with the NODA was a file comparable to the PTR "Detailed Unit-Level Data for State-Budgets, Unit Allocations, and Unit Emission Rates" (EPA-HQ-OAR-2009-0491-0074.1) (an Excel spreadsheet entitled "BADetailedData.xls"). Without this file, electric generating companies cannot determine the impact of the NODA on their allowance allocations. Although EPA did provide a new "IPM Run – TR Base Case v.4.10 – 2012 Parsed File" and a new "IPM Run-TR SB Limited Trading v.4.10 – 2014 Parsed File," without critically important additional information, electric generating companies cannot calculate the SO_2 or NOx allowance allocations for their units for 2012 or (where applicable) 2014.

EPA made "adjustments" to the IPM-projected unit-specific emissions for 2012, and provided these adjustments in the BADetailedData.xls file for the PTR. *See* BADetailedData.xls at the "Adjustments" tab. In addition to providing these EPA adjustments to the IPM results, the BADetailedData.xls file provided the projected unit-specific operating parameters (*e.g.*, heat rates, emission rates, and controls) in one location, allowing electric generating companies to check EPA's assumptions and better understand how EPA calculated each unit's allocations. The BADetailedData.xls file also clarified whether a state's annual 2012 NOx and SO_2 unit allocations and seasonal NOx unit allocations were based on reported data or on the 2012 IPM projections. As described in EPA's Technical Support Document ("TSD") on "State Budgets, Unit Allocations, and Unit Emissions Rates" ("State Budgets TSD"),[3] EPA based the 2012 budgets (annual SO_2 and NOx and seasonal NOx) on the lower of the recent actual emissions (essentially the 2009 reported emissions for existing units, aggregated by state) or the 2012 IPM-projected base case emissions at the state level. In the BADetailedData.xls file, EPA indicated which emission amount was lower for each state and, thus, whether the 2009 "reported" emission amount or the 2012 "projected" emission amount served as the basis for the allowance allocations in that state. Without the BADetailedData.xls file, it is not possible to determine from the NODA the statewide budgets and the unit allowance allocations for 2012.[4] EPA should not proceed further with this rulemaking until it has provided this critical information for public review and comment.

In addition to not providing information needed to evaluate the effects of the NODA on state budgets and unit allowance allocations, EPA states in the NODA that it intends to change the NOx emission rates used in its calculations again before it takes final action in this rulemaking:

[3] EPA, "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD (July 2010), Docket ID No. EPA-HQ-OAR-2009-0491-0057, *available at* http://www.epa.gov/airquality/transport/pdfs/TSD_StateBudgets_July152010.pdf.

[4] Counsel for UARG e-mailed EPA's Clean Air Markets Division to request information regarding whether there was any way to calculate the 2012 statewide budgets from the information provided with the NODA, but EPA never responded to that request.

> EPA intends to update the NOx rates for fossil-fuel fired units in the final rule to reflect the more recent 2009 data. IPM v.4.10 and the previous version of IPM used for the Proposed Transport Rule analysis relied on 2007 unit level NOx rates. The updated NOx rates will more accurately portray the unit level control installations that have occurred at power plants during the past several years.[5]

These changes in the NOx rates will result in additional changes to the final unit-level allowance allocations. Electric generating companies will have no opportunity to review the new NOx rates assigned to their units and, thus, no opportunity to evaluate whether EPA made correct adjustments. Thus, EPA should also provide this information for public review and comment before proceeding to final action.

For the reasons discussed above and in UARG's PTR Comments, the proposed NOx and SO_2 allocations are likely to change due to a number of factors, including the many errors and ill-founded assumptions contained in NEEDS and IPM and reflected in the NODA information. EPA will presumably make at least some of the corrections requested in comments on the PTR and NODA. Fluctuation of allowance allocations prevents electric generating companies from planning for the future, which further exacerbates the problems associated with the extremely compressed schedule under EPA's proposal for installation of controls -- a matter discussed in detail in UARG's PTR comments.

In a stakeholder meeting held shortly after EPA issued the PTR but before its publication in the Federal Register, EPA requested that electric generating companies provide detailed comments correcting any inaccurate data or ill-founded assumptions that EPA made with respect to specific units. Publication of the NODA, which changes much of the information and many of the assumptions on which the PTR was based, has required electric generating companies to start over and to attempt, at considerable cost and with great difficulty, to repeat the same process --

[5] 75 Fed. Reg. at 53614/3 - 53615/1.

to the extent it is even possible to do so based on the limited and incomplete information provided by EPA. Yet EPA has, without explanation, failed to provide the information that would be necessary for companies to complete reviews similar to those that they undertook with respect to the PTR. Without the detailed information regarding key IPM runs and the assumptions associated with statewide budgets and unit-specific allocations discussed above, electric generating companies lack the information necessary to comment meaningfully on the impact of the NODA on the PTR. Thus, EPA has failed to provide an adequate opportunity for public review and comment on its proposal.

IV. EPA's Decision To Base 2014 SO_2 Allowance Allocations for Units in Group 1 States on the Same State-Level Emission Caps Used in the PTR -- Even Though Revised Data and an Updated Modeling Tool Were Available -- Is Arbitrary and Unjustified.

The primary purpose of the NODA was ostensibly to announce "an updated version of the power sector modeling platform that EPA proposes to use to support the final rule . . . consist[ing] of updated unit level input data ([NEEDS v4.10]) and a *set* of model run results with the updated modeling platform ([IPM] v4.10)."[6] The "set" of model run results that EPA elected to provide pursuant to the NODA was, in fact, seriously deficient, for reasons discussed in these comments. With respect to UARG's comments in section VII below, which urge EPA to redo its entire analysis using the updated NEEDS database and revised IPM platform, EPA's decision not to provide an updated "TR SO2 2000" IPM run, using the revised database and modeling platform, to establish new proposed 2014 SO_2 state budgets provides one of the clearest example of the flaws in EPA's process.

EPA stated in its State Budgets TSD that "[g]roup 1 state budgets are based on reductions projected to be cost-effective at $2000 per ton of SO_2 . . . [based on] . . . the IPM run [*i.e.*, TR

[6] 75 Fed. Reg. at 53613/1 (emphasis added).

SO2 2000]."[7] EPA did not state directly in the NODA that this critically important run would be omitted from the new data "set," but it got that point across nonetheless:

> These policy runs [*i.e.*, the limited set of runs that EPA provided] include the same State-level caps that EPA modeled in the Proposed Transport Rule. *The caps have not been modified to account for any changes that the new modeling might suggest; they are merely provided for informational purposes to allow commenters to understand the impact that changes in the model platform have on the projected impacts of the caps.*[8]

The "State-level caps" to which EPA apparently refers, *i.e.*, the 2014 SO_2 budgets for group 1 states, are the results of the TR SO2 2000 IPM run. The results of that run are input to the IPM Run – TR SB Limited Trading – Summary Report run and the unit-level parsed file for 2014. The practical effect of holding the 2014 SO_2 budgets for group 1 states constant and re-running the TR SB Limited Trading runs with the updated NEEDS database and IPM platform is that an individual unit's percentage of the state budget changes *but the state budget does not* -- *i.e.*, a unit's share of the "pie" changes but the size of the pie (artificially) remains the same. It would be far more relevant and more useful for electric generating companies (and states) to have access not only to the information provided with the NODA but *also* to a model run that demonstrates the effects of the updated database and modeling platform on the size of the state budgets. EPA must have known that "new modeling" of state budgets based on the updated NEEDS and IPM platform would not merely "suggest" revised emission caps[9] -- that new modeling in fact would plainly result in establishment of new caps at levels different from those proposed under the PTR. EPA provides no justification for its decision not to provide a TR SO2 2000 IPM run using the updated NEEDS database and IPM platform. In short, EPA's decision

[7] State Budgets TSD at 10.

[8] 75 Fed. Reg. at 53614/3 (emphasis added).

[9] *Id.*

to re-run the Limited Trading unit-level parsed file for 2014 with the revised NEEDS database and updated IPM platform while leaving state budgets the same -- based on the *un*revised data and IPM platform used in the PTR -- is illogical and arbitrary.

Although EPA's failure to provide the updated 2014 SO_2 budgets for group 1 states based on IPM v.4.10 undermines the public's ability to understand the impact of the updated NEEDS database and IPM platform on the state-level caps for 2014, even a cursory comparison of the limited set of new IPM runs provided with the NODA demonstrates that the impact of the updated NEEDS database and updated IPM platform must be significant. Among the few IPM runs based on the updated NEEDS database and updated IPM platform that EPA did provide in the NODA are the TR SB Limited Trading Summary reports for 2012, 2015, 2020, and 2030. The following comparisons of these reports with reports based on the corresponding IPM run using the earlier versions of NEEDS and IPM illustrate the dramatic impacts of using the new information:

- The total projected demand for power in 2015 is reduced by 230 GWh -- from 4,333 GWh in the PTR to 4,103 GWh in the NODA.
- The PTR projected 23.7 GW of new generation capacity from coal and 2.3 GW of new generation capacity from wind by 2015. The NODA projects only 2 GW of new generation capacity from coal and 22 GW of new generation capacity from wind by 2015 -- almost the exact inverse of EPA's projection for these two energy sources in the PTR.
- The PTR projected a total of 80.3 GW of flue gas desulfurization ("FGD") unit retrofits by 2015, while the NODA projects a total of only 49 GW of FGD retrofits by 2015.[10]

These very substantial changes in EPA's projections of the demand for power, the projected mix of new generation capacity, and projected pollution control retrofits suggest that it would be

[10] *Compare* "IPM Run – TR SB Limited Trading – Summary Report" (EPA-HQ-OAR-2009-0491-0088) *with* "IPM Run – TR SB Limited Trading v.4.10 – Summary Report" (EPA-HQ-OAR-2009-0491-0305).

reasonable to expect significant changes in the 2014 SO_2 budgets for group 1 states (as well as the 2012 SO_2 and NOx budgets) if those budgets are based on the revised versions of NEEDS and IPM. EPA thus should promptly provide the results of a re-run TR SO2 2000 using the new NEEDS and IPM versions.

V. Several of the Revisions to NEEDS and IPM that Are Reflected in the NODA Are Inappropriate or Inadequately Explained.

A. EPA's Upward Adjustment of Its Assumption Regarding FGD Maximum Removal Efficiency Is Unjustified and Inaccurate.

EPA states in its IPM v.4.10 Documentation that it assumes a maximum SO_2 emission removal efficiency for wet FGDs of 98%, representing an increase of three percentage points over the maximum percentage removal assumption used in the version of IPM on which EPA relied in developing the PTR. *Compare* IPM v.4.10 Documentation at 5-2 with EPA, "Updates to EPA Base Case v.3.02 EISA Using the Integrated Planning Model" ("Base Case v.3.02 TSD") at 8 n.3 (July 2010), Docket ID No. EPA-HQ-OAR-2009-0491-0052, *available at* http://www.epa.gov/airquality/transport/tech.html. EPA does not provide an explanation or any justification for this upward revision in assumed wet FGD removal efficiency, other than to say that, in transferring data from the EIA's Form 767 for use in IPM v.4.10, "changes were made." Base Case v.4.10 Documentation at 5-2. EPA states further that, in modeling the effects of installing wet FGDs, EPA assumed that the new scrubbers would operate at maximum efficiency. *Id.* ("existing units that are selected to be retrofitted by the model with [wet] scrubbers are given the maximum removal efficienc[y] of 98% . . . . Potential (new) coal-fired units built by the model are also assumed with a [wet] scrubber achieving a removal efficiency of 98% . . . ."). In the absence of a more explicit explanation by EPA, commenters can only presume that this is an assumption of *continuous* control efficiency of 98%. It is unreasonable for EPA to assume that new FGDs will always operate at maximum efficiency, regardless of the percentage of SO_2 that is estimated to be removed at maximum efficiency. Equally important, the level at which EPA assumes wet FGDs will operate -- 98% -- is unrealistic.

A recent study of the best-performing FGD equipment -- evaluating the removal performance of the ten lowest SO_2 emitting units nationwide -- concluded that "none of these 'top performing' wet FGD systems was able to achieve a removal efficiency of 98% or greater in every month of the year." *See* Cichanowicz, J.E., "Overview of Information on Projected Control Technology Costs and Performance as Developed for EPA's Integrated Planning Model (IPM)," at 4 (Oct. 15, 2010) (hereinafter "Cichanowicz Report")[11] (quoting Weilert, C.V., et al., "Emissions Control Performance Achieved in Practice by Electric Utility FGD Systems in the United States," at 12, proceedings of the 2010 Power Plant Air Pollutant Control MEGA Symposium (Aug. 30-Sept. 2, 2010, Baltimore, Maryland)). In fact, the available data suggest that even top-performing wet FGD units are unable to achieve consistent, annual average reduction levels of more than perhaps 95% to 96% SO_2 removal. *Id.*

EPA's assumption that the "new" scrubbers that IPM projects will be installed in the coming years will operate continuously and consistently at 98% efficiency -- a level perhaps 2 to 3 percentage points above the efficiency level that they may be likely to actually achieve on an annual average -- will result in an insufficient number of allowances being allocated to units projected to add new FGD. Thus, based on EPA's proposal, units projected to be retrofit with wet scrubbers will have insufficient allowances at the start of each control year and will be forced to purchase allowances to make up the difference.

This effect of EPA's unrealistic assumption regarding the removal efficiency of new wet FGDs is exacerbated by the fact that EPA proposes to reduce allowance allocations by 3% to

[11] The Cichanowicz Report was prepared to support these comments. It is attached and is incorporated herein by reference.

create an allowance set-aside for new units before distributing allowances to existing units. *See* 75 Fed. Reg. at 45309/1. Given that EPA plans to set aside 3% of each state's allowance budget for new units and distribute the remaining 97% among existing units, the Agency should be all the more careful to avoid making unrealistically aggressive assumptions regarding removal efficiency.[12]

EPA should adjust its assumption regarding the control efficiency at which new scrubbers will operate to reflect a more realistic annual-average maximum-removal assumption of 95% to 96% and recalculate state budgets and unit-level allocations accordingly.

B. Units with Generating Capacity Less than 100 MW Cannot Properly Be Assumed To Be Candidates for Installation of FGD or SCR.

EPA explains in its Base Case v.4.10 Documentation that IPM v.4.10 assumes that units with generating capacities between 25 MW and 100 MW are candidates for installation of FGD and selective catalytic reduction ("SCR").[13] However, in the base case for the PTR, EPA assumed that "coal-fired EGUs under 100 MW capacity *[did] not have the option of retrofitting FGD or SCR*." Base Case v.3.02 TSD at 20 (emphasis added). EPA fails to provide any plausible explanation for changing this assumption.

In fact, EPA's new assumption that units with capacities between 25 MW and 100 MW can be retrofit with FGD and SCR is unrealistic. In many cases, it is impossible to retrofit units

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[12] The same point applies to assumptions regarding other emission controls, including NOx controls.

[13] Base Case v.4.10 Documentation at 5-13. For modeling purposes, IPM v.4.10 effectively assumes that the cost of adding emission controls to units in this MW range is equivalent to the cost of adding controls to a 100 MW unit. This assumption is based on the notion that several small units are likely to be ducted to share a common control, and that single units that are not ducted are likely to have the option of installing hybrid multi-pollutant controls, which are currently under development. *Id.* at 5-13 to 5-14; *see also* Cichanowicz Report at 10-11 (discussing treatment of smaller units in control-cost analysis).

with capacity below 100 MW with FGD and SCR. And in cases where it is technically possible to do so, it would rarely, if ever, be cost-effective. EPA acknowledged in its Base Case v.3.02 TSD that "FGD and SCR retrofits to such small units are very costly in any case." *Id.* The emission reduction (and air quality improvement) benefits to be gained from such a large expense are quite limited due to the low emission amounts from "such small units." Thus, even in cases where below-100 MW units theoretically could be retrofit with FGD or SCR, it would not be an economic choice to do so, at least in the great majority of cases.

EPA should recalculate its base case emission inventories to remove the assumption that small units, with capacities between 25 MW and 100 MW, can be retrofit with FGD and SCR. At a minimum, EPA should explain its reasoning for changing its assumption regarding small unit retrofits in the NODA.

C. EPA May Well Be Understating SCR Capital Costs.

UARG supports EPA's decision to retain Sargent & Lundy ("S&L") to estimate control technology costs for the Proposed Transport Rule based on S&L's database of component costs and installation charges. Using a firm that specializes in determining the average costs of installation, operation, and maintenance of electric power generation and emission control equipment is likely to produce data that is more accurate than if EPA had pursued certain other cost-estimation approaches. *See* Cichanowicz Report at 1.

Although UARG believes that many of S&L's cost estimates are reasonable and likely to be accurate, or close to accurate, *see generally id.*, S&L's projected capital cost of adding SCR appears likely to be an underestimate. *See id.* at 7-9 (describing differences between S&L's estimates and those provided as a result of a recent UARG survey and discussing possible reasons for those differences).

This apparent underestimate of SCR costs can affect the calculations and assumptions on which EPA relies in the Proposed Transport Rule, including the creation and evaluation of cost curves in EPA's multi-factor analysis for determining emission reduction obligations under the PTR and the selection of "breakpoints" for emission controls, based on the cost curves. Furthermore, the S&L estimates reflected in the NODA differ from the control cost estimates that EPA used for its analyses in the PTR. EPA's use of these different cost estimates will affect EPA's analyses, regardless of whether the new cost estimates are more or less accurate than the estimates used for the PTR. *See also* section VII *infra*. EPA should therefore revise its analyses using appropriate control cost estimates and allow for public comment on the results.

D. EPA's Revised NEEDS Database and IPM Platform Still Contain Numerous Errors and Have Introduced Additional Inaccurate Assumptions.

As discussed in section VIII of UARG's comments on the PTR, NEEDS v.3.02 and IPM v.3.02 contained many inaccurate inputs, in the form of errors in NEEDS, inaccurate IPM constraints, and inaccurate outputs. Despite the limited time provided for UARG members to check the accuracy of the "updated" NEEDS v.4.10 and IPM v.4.10, UARG and its members have discovered that it appears that EPA has introduced additional errors and inaccurate assumptions in the updated versions, while leaving many earlier problems uncorrected. As illustrated by the discussion in section V.A *supra*, certain systemic adjustments to EPA's assumptions regarding new FGD control efficiencies are inconsistent with real-world experience and would result in inadequate allowance allocations. Moreover, unit-specific examples of changed assumptions are provided below. In addition to the same categories of errors and assumptions catalogued in UARG's comments on the PTR, new assumptions in IPM v.4.10 regarding fuel prices and the cost of control technologies appear to have resulted in a new category of errors -- errors related to, for example, the retirement of coal-fired units and the controls that existing units are projected to install.[14]

Examples of errors and incorrect assumptions in NEEDS v.4.10 include:

- NEEDS v.4.10 reports that Units 1-3 at the Baldwin Energy Complex in Illinois are currently equipped with wet FGD systems. That is incorrect. As a result of a consent decree, Unit 1 is required to install a dry FGD system by the end of 2011, Unit 2 is required to install a dry FGD system by the end of 2012, and Unit 3 is required to install a dry FGD system by the end of 2013. NEEDS also assumes a 98% removal efficiency for wet FGD, which, for reasons set forth above, could not be assumed to be achievable on an annual basis even if these units were to install wet rather than dry FGD.

- NEEDS v.4.10 reports that Units 1-3 at the Baldwin Energy Complex in Illinois are currently equipped with cold-side electrostatic precipitators ("ESPs") and baghouses. This is incorrect. Although these units are currently equipped with ESPs, Unit 1, Unit 2, and Unit 3 are not required to construct baghouses until the end of 2011, 2012 and 2013, respectively.

- NEEDS v.4.10 reports that Units 1 and 2 at the Baldwin Energy Complex in Illinois have an uncontrolled NOx rate of 0.0723 lb/mmBtu. Based on continuous emission monitoring system ("CEMS") data previously reported to EPA, the uncontrolled rate of these units is 0.61 lb/mmBtu.

- NEEDS v.4.10 reports that Unit 9 at the Havana Station in Illinois has an uncontrolled NOx rate of 0.0723 lb/mmBtu. Based on CEMS data previously reported to EPA, the uncontrolled rate of this unit is 0.61 lb/mmBtu.

- NEEDS v.4.10 reports that Unit 2 at the Ghent facility in Kentucky had an SCR installed as of 2009. That unit does not have an SCR, and installation of SCR is not planned at that unit.

- NEEDS v.4.10 reports that two units at the Armstrong power station in Pennsylvania have installed selective noncatalytic reduction ("SNCR"). A Mobotech Rotamix system was installed in 2003 in an effort to reduce NOx, but the equipment was ineffective and was removed.

- NEEDS v.4.10 reports FGD removal efficiency at the Mitchell power station in Pennsylvania as 99.9% and at the Pleasants power station in West Virginia as 97%. These removal efficiencies are incorrect. Actual removal efficiency at the Mitchell

[14] For additional discussion of issues associated with retirement of coal-fired generation and erroneous control assumptions for coal-fired generation, *see* Comments of the Midwest Ozone Group on the NODA.

power station averages 97% and actual removal efficiency at the Pleasants power station averages 95%.

Examples of errors in IPM outputs and erroneous IPM inputs include:

- IPM v.4.10 reports in both the TR_SB_Limited Trading parsed files that the primary fuel for Units 1 and 2 at the Danskammer power station in New York is natural gas. The primary fuel for both units is oil.
- IPM v.4.10 reports in both the TR SB Limited_Trading parsed files that the primary fuel for Units 1 and 2 at the Roseton power station in New York is natural gas. The primary fuel for both units is oil.
- IPM v.4.10 reports NOx controls for Unit 4 at the Scherer power station in Georgia consisting of low NOx burners and separated overfire air. This is inaccurate -- only overfire air is installed at that unit.
- IPM v.4.10 reports in the 2014 TR_SB_Limited_Trading parsed file that the coal-fired Unit 3 at the Sibley power station in Missouri will retire early. SCR was installed in 2009, making it highly unlikely that the unit will retire in or by 2014.
- IPM v.4.10 reports in the 2014 TR_SB_Limited_Trading parsed file that the coal-fired Mount Tom power station in Massachusetts will retire early. Dry FGD was installed in 2009, making it highly unlikely that that facility will retire in or by 2014.
- IPM v.4.10 reports in the 2014 TR_SB_Limited_Trading parsed file that the coal-fired Unit 4 at the Indian River power station in Delaware will retire early. Installation of dry FGD is planned for 2012, making it unlikely that the unit will retire in or by 2014.

The specific errors cited above are provided as examples of the types of mistakes found in the updated NEEDS and IPM modeling -- they represent a mere sampling of the problems found by electric generating companies. In order to provide an adequate opportunity to comment on proposed unit-level allowance allocations, EPA should correct these errors and publish a revised allocation table for comment.

In addition to the flawed IPM outputs for specific units, other outputs provided on a regional scale in the IPM Run – TR SB Limited Trading v.4.10 – Summary Report do not seem plausible and call into question the accuracy and validity of the modeling results. Two examples are (1) IPM's forecast for additional wind generation by 2015 and (2) IPM's projected SO_2 allowance price.

As mentioned above, the IPM Run TR SB Limited Trading Summary Report projected 23.7 GW of new generation capacity from coal and 2.3 GW of new generation capacity from wind in 2015. The IPM Run TR SB Limited Trading v.4.10 – Summary Report projects only 2 GW of new generation capacity from coal and 22 GW of new generation capacity from wind in 2015. The magnitude of the projected increase in predicted new wind generation between successive versions of the model calls into question the validity of the model results. In any event, even if there is some "logical" justification for IPM's projection of 22 GW of new wind generation, there are certain practicalities that make that projection doubtful. As of January 1, 2010, the total installed wind generation capacity in the United States stood at 35 GW.[15] IPM predicts that 21 of the 22 GW of projected new wind generation will be online by 2012. Thus, the additional wind generation that EPA projects would constitute a 60% increase in the United States capacity in approximately three years.[16] Considering that the average-sized wind farm in 2009 had generation capacity of 91 MW,[17] that would mean that approximately 231 average-sized wind farms would have to be permitted and built by 2012. According to the American Wind Energy Association, it takes approximately 18 months to two years to permit and build

[15] U.S. Department of Energy, "2009 Wind Technologies Market Report" at iii (Aug. 2010) ("2009 Wind Report"), *available at* http://www1.eere.energy.gov/windandhydro/.

[16] IPM results provide no indication of where this additional wind generation will be located. Thus, there is no way to determine whether it will be located within the states regulated by the PTR.

[17] 2009 Wind Report at v.

even relatively small (50 MW) wind farms.[18] The dramatic change in generation mix between successive versions of IPM and practical considerations of actually permitting and building that many new wind farms in a very short period call for explanation and additional justification by EPA of this very substantial change in its projections.

Finally, the IPM Run – TR SB Limited Trading v.4.10 – Summary Report provides estimates of SO_2 allowance prices for group 1 and group 2 states at $313 and $184, respectively.[19] Although it is not possible to compare these prices to projections from the IPM Run – TR SB Limited Trading – Summary Report because allowance price projections were not provided in that report, a report by James Marchetti for the Midwest Ozone Group ("MOG") and submitted with MOG's comments on the NODA notes that the cost in 2015 of SO_2 allowances in a group 1 state under an intra-state-only trading regime was estimated at approximately $1,900 per allowance.[20] At best, this analysis demonstrates that the IPM projection of 2015 SO_2 allowance prices is considerably underestimated. At worst, this analysis suggest a flaw in IPM's methodology.

VI. In Making the Changes Represented in the NODA, EPA Continues To Ignore the Effects of CAIR and Local Controls.

EPA indicates that IPM v.4.10 takes into account all existing federal and state air emission regulations (except for CAIR), as well as new source review ("NSR") and other settlements, that were in effect or were final as of August 2010. Base Case v.4.10

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[18] *See* "Wind Energy Basics" from the American Wind Energy Association, *available at* http://www.awea.org/faq/wwt_basics.html.

[19] *See* "IPM Run – TR SB Limited Trading v.4.10 – Summary Report" (EPA-HQ-OAR-2009-0491-0305).

[20] *See* Marchetti, J., "Final Report: MOG Comments on the NODA," at 9-10 (Oct. 15, 2010), submitted to the docket for this rulemaking as an attachment to MOG's comments on the NODA.

Documentation at 1-1.[21] By contrast, the previous version of IPM, used to model the PTR, took into account these same factors effective as of February 3, 2009. 75 Fed. Reg. at 45243/2. Despite this updating by about 18 months with respect to EGU emission limitations, EPA in the NODA improperly continues to ignore the effects of CAIR and local emission controls, including controls affecting emissions from non-EGU point sources and nonpoint stationary sources.

A. EPA Should Have Considered the Effects of CAIR.

As UARG explained in its comments on the PTR, EPA should have included CAIR in its base case modeling because it remains binding law until it is replaced by a valid rule. *See* UARG's PTR Comments at 50-53. According to the terms of the D.C. Circuit's December 2008 opinion on rehearing in *North Carolina v. EPA*, CAIR will remain binding law until a new rule is in place. Thus, it is appropriate for EPA to conclude in this rulemaking that there will be no time when neither CAIR nor a CAIR replacement rule will be in effect. *See id.* at 50-51. Additionally, EPA has not demonstrated that EGUs in the few states that were regulated under CAIR but may not be regulated under the Transport Rule, as proposed, are likely to increase their emissions when CAIR expires, or that such increases would be permitted under state law. In reality, these EGUs have already made reductions pursuant to CAIR and it is very unlikely that they will increase their emissions to pre-CAIR levels once CAIR expires. Based on these factors, as well as the downward trend that EPA has acknowledged in $PM_{2.5}$ and ozone

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[21] *See also* Base Case v.4.10 Documentation at Appendix 3-2 ("State Power Sector Regulations [I]ncluded in EPA Base Case v.4.10"), Appendix 3-3 ("[NSR] Settlements in EPA Base Case v.4.10"), Appendix 3-4 ("State Settlements in EPA Base Case v.4.10"), Appendix 3-5 ("Citizen Settlements in EPA Base Case v.4.10"), Appendix 3-6 ("Renewable Portfolio Standards in EPA Base Case v. 4.10").

concentrations nationwide,[22] it is far more realistic to assume that CAIR applies than it is to assume that it does not. *See* UARG's PTR Comments at 52-53.

B. EPA Should Have Considered the Effects of Local Controls.

UARG also explained in its comments on the PTR that EPA's proposal improperly failed to account for local emission controls. Section 107(a) of the CAA states that "[e]ach State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State." 42 U.S.C. § 7407(a). *See* UARG's PTR Comments at 64-66. Thus, EPA's proposal to promulgate and implement a rule that regulates sources of transported pollutants without considering the effects of local controls, *see* 75 Fed. Reg. at 45226/3, is contrary to the Act. EPA attempted to explain its failure to account for local controls in the PTR by asserting that "nonattainment areas for the 1997 $PM_{2.5}$ and ozone standards were not announced until 2004 and 2005 respectively, and the corresponding [SIPs] were not due until 2007 and 2008, thereby preventing the inclusion of these local measures in the 2005 emissions inventory." EPA, "Emissions Inventories" TSD ("Emissions TSD") at 11 (June 2010), Docket ID No. EPA-HQ-OAR-2009-0491-0050, *available at* http://www.epa.gov/airquality/transport/tech.html. As UARG noted in its comments on the PTR, however, the unavailability of this information in 2005 does not explain EPA's failure to account for it in its future base case projections. *See* UARG's PTR Comments at 65 n.39. Again, despite the many updates reflected in the NODA, EPA fails to account for local controls. EPA must consider the effects of local controls on its modeling and on air quality and attainment and interference with maintenance of the NAAQS.

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[22] *See* EPA, "Our Nation's Air Status and Trends Through 2008," 1-2 (Feb. 2010), *available at* http://www.epa.gov/airtrends/2010/index.html.

Moreover, even if one were to accept that EPA had insufficient time to account for local controls in the entire proposed control region before issuing the PTR, EPA could and should have at least considered the effects of local controls on the areas surrounding the six monitors with perceived maintenance problems that led to EPA's proposed designation of the group 1 states that are subject to additional SO_2 reduction requirements in 2014. *See* UARG's PTR Comments at 61-64 (discussing EPA's classification of group 1 states based on six monitors with perceived maintenance problems). EPA certainly has the resources to consider the effects of local controls in the areas surrounding these six monitors.[23] Such consideration of local controls may have eliminated the need (as determined by EPA) for additional SO_2 reduction requirements in 2014, or at least may have reduced the number of group 1 states.

VII. The Availability of NEEDS v.4.10 and IPM v.4.10 and the Central Role These Items Play in the Structure of EPA's PTR Warrant a New or Supplemental Proposed Rule Based on the Results of the New Data and Modeling.

EPA's PTR depends in substantial measure on the validity, reliability, and accuracy of IPM. No other tool has as great an influence on key elements of the PTR. Indeed, the results of IPM runs have a direct or indirect effect on every major step in EPA's PTR methodology. In the NODA, EPA acknowledged as much by stating:

> Changes from the projections relied on in the proposed rule, from using an updated model, could impact the final rulemaking in a number of ways including, but not limited to:
>
> 1. Changing emission projections that were used to determine which downwind areas have air quality concerns (*i.e.*, non-attainment or maintenance) absent this rulemaking and to determine which States contribute to those problems.
>
> 2. Changing cost and emission projections used in the multi-factor [*e.g.*, cost curve] test to determine the amount of emissions that represent significant contribution.

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[23] In fact, UARG notes that two of the six monitors are located in Allegheny County, Pennsylvania. Thus, EPA would have had to consider local controls in only five local areas.

75 Fed. Reg. at 53614/3. If anything, EPA understates the potential impact of the updated database and platform. The NEEDS inventory and the output of IPM substantially influence the fundamental components of the PTR: the analyses of air quality; the linkages of upwind states to downwind problem areas; the definition of significant contribution to nonattainment and interference with maintenance; and the establishment of statewide budgets and unit-specific allocations.

Despite the central role of IPM in each of these components, EPA elected to provide a very limited number of runs using the updated NEEDS database and revised IPM platform and then further qualified the import of the runs by stating that "they are merely provided for informational purposes to allow commenters to understand the impact that changes in the model platform have on the projected impacts of the caps."[24] It is unclear why EPA tries to downplay the potential impact of the updated NEEDS database and IPM platform when EPA clearly "proposes to use this version of the IPM model [IPM v.4.10] in the final Transport Rule."[25] As discussed in section IV above, a cursory comparison of the NODA IPM runs with the PTR IPM runs demonstrates that changing the NEEDS emission inventory and using an updated IPM version result in significantly different outcomes.

UARG appreciates that entirely redoing EPA's analysis using the updated NEEDS database and IPM platform takes significant time and resources. EPA should, however, conduct its analysis using the most current model and information at its disposal, and then should make all the results available to the public and allow an adequate time for public review and comment before taking any final action in this rulemaking.

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[24] 75 Fed. Reg. 53614/3.

[25] *Id.*

In all its complexity, EPA's PTR methodology can be broken down into approximately eight major steps. In each of these steps, IPM provides information critical to the accuracy and validity of EPA's analysis. The purpose of reviewing each of these steps is to demonstrate EPA's thoroughgoing reliance in this rulemaking on IPM and the importance of EPA undertaking a full analysis with the revised modeling tool and data, and allowing a full opportunity for public comment on the methodology and results of that analysis.

The following paragraphs describe the eight major steps in EPA's methodology, as reflected in the PTR, and discuss why these steps depend on IPM results:

1. EPA created four emission inventory cases to support air quality modeling. EPA created four "complete" emissions cases to support its air quality modeling and analysis. The principal input to the Comprehensive Air Quality Model with Extensions ("CAMx"), which EPA used for its air quality modeling, is the emission inventory for each source sector. EPA refers to its four inventory cases as the 2005 base case, the 2012 base case, the 2014 base case, and the 2014 control/policy case.[26] These emissions cases are complete in that they contain estimates of emissions for each of the main source sectors: EGUs, non-EGU point sources, nonpoint (area) stationary sources, onroad mobile sources, nonroad mobile sources, and fires. The EGU portion of the SO_2 emissions constitutes a majority of the total SO_2 emissions for 2005 (*e.g.*, for the 2005 base case in the PTR, 10,019,774 tons of the total 13,380,267 tons of SO_2 emissions).[27] The EGU portion of the NOx emissions represents about a fifth of the overall NOx emissions for 2005 (3,223,184 tons of the total 15,943,047 tons of NOx emissions for the base case).[28] For the three future emissions cases (the 2012 base case, the 2014 base case, and the 2014 control/policy case), EPA relied on IPM to project the EGU portion of the complete emission inventory.[29] Thus, IPM is the source of the emission

[26] Emissions TSD at 6.

[27] 75 Fed. Reg. at 45240 (Table IV.C-1).

[28] *Id.* at 45240-41 (Table IV.C-2).

[29] Emissions TSD at 11, 37.

estimates for two of the most significant precursors to $PM_{2.5}$ and ozone formation in the CAMx atmospheric modeling.[30]

2. The IPM-dependent CAMx modeling was used to project future downwind $PM_{2.5}$ and ozone nonattainment and maintenance problems. A critical first step in predicting future nonattainment and maintenance problem monitors for the annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and 8-hour ozone NAAQS involved calculating the relative changes from the 2005 base case modeling results from CAMx to the 2012 base case model run results.[31] The CAMx atmospheric modeling runs depend in considerable part on the IPM emission projections for 2005 and 2012 because those are among the most influential inputs to the modeling, and changes to the 2012 base case model run results due to changes in IPM will affect the results of this step of the analysis.

3. EPA used IPM-dependent CAMx modeling to assess interstate contributions to nonattainment and maintenance. After EPA used CAMx to model future nonattainment and maintenance problems at downwind monitors, EPA used the photochemical source apportionment feature of CAMx to "quantify the impact of emissions in specific upwind states on air quality concentrations in projected downwind nonattainment and maintenance locations."[32] As discussed in step 1, EGU emissions make up the large majority of SO_2 emissions and approximately one-fifth of NOx emissions. Consequently, one of the most influential emission source categories in shaping the results of the CAMx source apportionment modeling is the EGU source sector, whose estimated emissions depend on IPM projections.

4. After establishing state linkages to downwind nonattainment and maintenance sites, EPA's first step to quantify significant contribution -- *i.e.*, creation of emission reduction cost curves -- depends entirely on IPM modeling results. EPA's first step in "determining the quantity of emissions that represents each state's significant contribution is to identify reductions available at different costs."[33] EPA developed "cost curves" that are intended to show the available emission reductions from EGUs at various dollar-per-ton cost increments. EPA derived the amount of emission reductions available at each cost

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[30] For this and the subsequent steps described in this section of UARG's comments on the NODA, UARG recognizes that it is conceivable that EPA has used this new, updated information in its analyses -- but, critically, if EPA has done so, it has not disclosed that fact in the NODA information and has not provided the results to the public for review and comment.

[31] 75 Fed. Reg. at 45246/3 - 45247/3 (annual $PM_{2.5}$ methodology); *id.* at 45248/1 - 45249/3 (24-hour $PM_{2.5}$ methodology); *id.* at 45252/1-3 (8-hour ozone methodology).

[32] *Id.* at 45253/1.

[33] *Id.* at 45272/2.

increment from IPM; the cost curves are a direct output of IPM.[34] The relevance and accuracy of the cost curves thus depend on IPM.

5. EPA used its air quality assessment tool ("AQAT") to estimate the air quality benefits of upwind emission reductions on downwind ambient concentrations of $PM_{2.5}$ and ozone. Instead of using CAMx as a primary tool to evaluate the downwind benefit of upwind emission reductions, EPA created its AQAT. Unlike CAMx, AQAT is not a dynamic air quality model but is essentially an Excel spreadsheet that generates estimates of downwind ambient pollutant concentrations based on the amounts of emissions from an upwind state. "For each downwind area with a nonattainment and/or maintenance problem, it shows the total improvement in air quality for each cost level and associated pollutant reduction . . . ."[35] The amount of the pollutant reduction that is available at each cost level is a direct output of the IPM model runs. In addition to the updates to the NEEDS emission inventory that is input to IPM, one of the changes from IPM v.3.02 to IPM v.4.10 was a "major update of emission control technology assumptions[]," which in turn involved changes to the estimates of costs associated with NOx and SO_2 emission controls.[36] Consequently, in this step perhaps more than in any other, the updates reflected in the latest version of IPM would have produced different results.

6. EPA evaluated the results of the IPM-dependent AQAT to establish control cost thresholds, or "breakpoints." EPA evaluated the air quality benefits predicted by AQAT at the various cost levels on the cost curves and identified "breakpoints" -- "places where there is a noticeable change on one of the cost curves, such as a point where a large reduction occurs because a certain type of emissions control becomes cost-effective."[37] EPA selected a breakpoint of \$2,000/ton for SO_2 and a breakpoint of \$500/ton for NOx.[38] The cost curves and results of the AQAT would be different if EPA had used the latest version of IPM. When the assumed costs of control technologies change, as they did pursuant to the NODA information, there is every reason to believe that the "breakpoints," where large emission reductions become available because a technology becomes cost-effective, also would change.

7. EPA established SO_2 emission budgets for group 1 states based on an IPM run; IPM runs also influenced 2012 state budgets for both SO_2 and NOx. Using its cost-curve breakpoint for SO_2, EPA set the group 1 statewide 2014

[34] *Id.*

[35] *Id.* at 45273/3.

[36] Base Case v.4.10 Documentation at 5-1.

[37] 75 Fed. Reg. at 45271/1-2.

[38] *Id.* at 45281/2-3 (SO_2); *id.* at 45288/2 (NOx).

SO_2 emission budgets based on the emission reductions projected to be cost-effective at $2,000 per ton of SO_2. The state budgets were a direct output from a single IPM run, referred to as "TR SO2 2000."[39] The 2012 SO_2 and NOx budgets are also influenced by the NEEDS inventory and IPM because EPA calculated budgets based on the operation of existing controls, controls that EPA projects to be operational by 2012, and EPA-projected switches to lower-sulfur coal.[40] The calculation of these budgets is dependent on the accuracy of both the NEEDS emissions inventory and the IPM assumptions regarding when installation or use of various controls is economical and the level of emission reductions that can be achieved by those controls.

8. <u>EPA established unit-specific NOx and SO_2 allowance allocations</u>. For units in group 1 states, EPA established 2014 unit-specific SO_2 allocations as "a proportional share of the state's budget based on projected SO_2 emissions from fossil-fired greater than 25 MW capacity units in the [2014] TR SB Limited Trading IPM run, as apportioned to the unit level in the 2014 parsed file" (minus 3% of the emissions that EPA allocated to establish the new unit set-asides).[41] EPA based the 2012 unit-specific allocations for annual SO_2 emissions, annual NOx emissions, and seasonal NOx emission on the lower of either the most recent actual reported cumulative emissions from all affected EGUs within a state or the cumulative 2012 IPM base case projection for each state. "The proposed unit-level allocations are calculated analogous[ly] with the way each state budget is calculated -- each unit receives a proportional share of its state budget based on that unit's share of state emissions assumed in developing the budget [minus 3% to establish the new unit set-aside]."[42] If a state's 2012 budget was based on the IPM 2012 projection (because the state's 2012 projected emissions were lower than its actual reported emissions), then the individual allocations for units in that state were based on the projected emissions for units in the same IPM Run-Parsed File SB Limited Trading run that contained the 2012 unit-level emissions. Yet, without offering any particular explanation as to why it replicated certain portions of *this* step using the new IPM version even though it did not do so for earlier steps, EPA recalculated the 2014 unit-level SO_2 emissions for units in group 1 states in a new "SB Limited Trading v.4.10 2014 Parsed File"[43] -- but

[39] State Budgets TSD at 10.

[40] 75 Fed. Reg. at 45290/3. The State Budgets TSD clarifies that the 2012 NOx and SO_2 "budgets are the lower of the recent actual emissions [approximately 2009] or projected base emissions, at the state level." State Budgets TSD at 9.

[41] State Budgets TSD at 12.

[42] *Id.* at 11.

[43] IPM Run – TR SB Limited Trading v.4.10 – 2014 Parsed File (EPA-HQ-OAR-2009-0491-0312).

> apparently limited by the original proposed state emission budgets derived from the PTR IPM-based TR_2000_SO2. Without explanation, EPA elected not to provide for public review and comment the parsed results for 2012 unit-specific emissions based on the updated NEEDS database and IPM platform.

As the discussion above indicates, at every major step in EPA's methodology -- *e.g.*, creating emission inventory cases as inputs to CAMx modeling, projecting future nonattainment and maintenance problem areas, establishing linkages of upwind states to downwind nonattainment and maintenance problem areas, defining significant contribution to nonattainment and interference with maintenance, and establishing unit-specific allocations -- IPM played an indisputably critical role in ultimately determining unit-specific allowance allocations.

Although EPA states in the NODA that it proposes to use IPM v.4.10 (along with NEEDS v.4.10) "in the final Transport Rule,"[44] the NODA is unclear as to exactly where and how EPA intends to use it. EPA should clarify these issues for the public and should revisit the basis for its proposal if it intends to proceed with this rulemaking and to continue to use its proposed approach to implementing section 110(a)(2)(D)(i)(I) of the Act. In doing so, EPA should redo each step of its methodology as described above using the updated NEEDS inventory and IPM platform. EPA then should issue the results of its new analysis for public review and comment, providing an adequate comment period.

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[44] 75 Fed. Reg. at 53614/3.

OVERVIEW OF INFORMATION ON PROJECTED CONTROL TECHNOLOGY COSTS AND PERFORMANCE AS DEVELOPED FOR EPA'S INTEGRATED PLANNING MODEL (IPM)

October 15, 2010

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OVERVIEW OF INFORMATION ON PROJECTED CONTROL TECHNOLOGY COSTS AND PERFORMANCE AS DEVELOPED FOR EPA'S INTEGRATED PLANNING MODEL

INTRODUCTION

This document reviews and responds to information on projected SO2 and NOx control technology costs as developed by Sargent & Lundy Engineers (S&L) for the Environmental Protection Agency (EPA), for use in a new version (v.4.10) of the Integrated Planning Model (IPM), and as reported by EPA (EPA, 2010a). S&L's information on costs and performance is reviewed and compared to other recent data derived for similar control technologies. For example, S&L's cost data are compared to cost data developed in a 2009 survey of utility industry operators and reported by the Utility Air Regulatory Group (UARG, 2010). S&L's information on the performance of control technologies is evaluated and compared to other recent data, including data from a recent study of the best-performing wet and dry FGD equipment (Weilert, 2010).

The control technologies addressed are wet and dry flue gas desulfurization (FGD) for control of SO2; and selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and combustion controls for control of NOx. (The referenced EPA report also address costs for control of mercury (Hg), but the cost of equipment for reducing Hg emissions is not reviewed in this analysis.)

APPROACH

EPA's approach to acquiring cost data for use in v. 4.10 of IPM is very different from the approach the Agency took in conducting past studies to develop the same information. In the present case, EPA engaged S&L to develop such inputs. Historically, EPA either derived such costs with internal staff, after discussions with control equipment suppliers, or employed contractors that had limited access to information on equipment cost and performance. By engaging an architectural/engineering firm with broad experience working with electric generating companies, EPA accessed an authentic database of component and installed costs.

S&L applied their in-house database of control technology component costs and their knowledge of installation requirements and maintenance duties to project realistic cost estimates. S&L then used this database to estimate fixed and variable O&M costs for the different categories of control technology. Once the size of the control equipment was determined, and the coal composition was considered, S&L

applied conventional cost indices for installation of delivered equipment to determine final costs. This approach replicates the steps in a commercial project.

Table 5-3 in the S&L report lists the factors considered in the cost evaluation. This table comprises a representative and comprehensive list.

S&L note that by adopting these most recent cost estimates into the IPM, EPA is apparently accepting that the escalation in capital costs for control equipment that was experienced in 2009 is permanent, with costs not expected to revert to levels preceding the 2009 installation window. Such an approach (EPA's adoption of the S&L projected costs into the IPM) is consistent with UARG's projection of FGD and SCR capital costs (UARG, 2010).

The following sections describe and evaluate S&L's data concerning the cost and performance of control technology for removing sulfur dioxide (SO2) and nitrogen oxide (NOx) emissions from power plants.

FLUE GAS DESULFURIZATION (SO2 CONTROL) PROCESS EQUIPMENT

Both conventional wet and dry flue gas desulfurization (FGD) are addressed. The specifics of the cost evaluation for wet FGD and dry FGD are described in companion documents prepared by S&L (EPA, 2010b, and EPA, 2010c).

Wet FGD

Estimated Costs. The capital cost for wet FGD process equipment as projected by S&L is shown in Figure 1, depicting capital cost ($/kW) as a function of generating capacity. Figure 1 presents data sets or curve-fits of data sets for three sources of wet FGD costs. S&L's projected capital costs are described by the blue line that is curve-fit through square data points, which reflect the 2010 IPM update costs described by EPA (2010b). This curve is labeled "2010 EPA IPM Projections". The red curve-fit through the locus of red triangle points represents capital costs for analogous wet FGD equipment, as reported in the 2010 UARG survey. This curve is labeled "2008-2010 Operating Units" and describes cost data that represent units at which the controls began commercial operation in that timeframe. Finally, the light blue curve reflects EPA's 2006 projected capital costs for wet FGD; these costs were used in EPA's previous IPM analysis (EPA, 2006). The cost data in Figure 1 for the EPA 2006 study case have been adjusted to a 2008 dollar basis.

Figure 1 shows that the wet FGD capital costs projected by S&L exceed by approximately 20-25% an average of the capital costs reported to UARG by plant owners. However, the curve-fit for S&L's projected costs resides within a portion of the UARG-reported cost data points for approximately 20 individual installations. Consequently, the difference in cost as reflected by the UARG and S&L curves –

although notable – is not considered significant. Given the paucity of data, either curve could be correct.

The capital costs in the two upper lines -- the 2010 EPA IPM Projections and Operating Units: 2008-2010 (*i.e.*, the costs reported for units at which the controls began commercial operation in 2008-2010) -- are significantly higher than the capital costs used in the 2006 EPA IPM analysis.

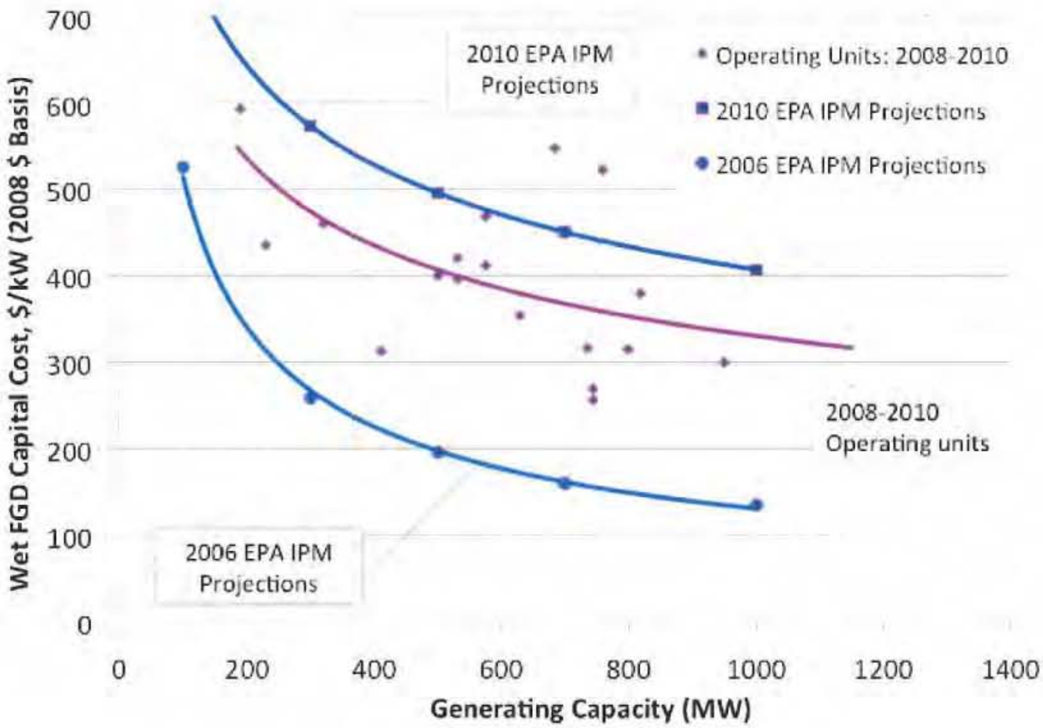

Figure 1. EPA-IPM Input for Wet FGD Capital Cost vs. UARG Survey Data

Fixed operating and variable operating costs for wet FGD equipment were also projected by S&L. For the range of generating capacity evaluated by S&L, the fixed operating costs projected by S&L are identical to UARG's estimates of fixed operating costs. S&L estimated variable operating costs only for one specific coal (3 lbs SO2/MBtu); this cost of 2.03 mills/kWh is within 10% of the projected cost in the UARG evaluation (2.2 mills/kWh).

<u>SO2 Removal Assumption</u>. The S&L analysis assumes 98% SO2 removal by wet FGD equipment, based on an annual average, with a minimum "floor" SO2 emission rate of 0.06 lbs/MBtu. Although present-generation wet FGD equipment can be capable of such high removal rates for abbreviated periods of time, the available data

suggest that such a level of performance cannot be achieved for each month of the year, for all coals.

A recent study of the best-performing wet FGD equipment suggests that 98% removal cannot be widely achieved on lower sulfur coals (Weilert, 2010). Specifically, Weilert evaluated the removal performance of the ten lowest SO2 emitting generating units in the U.S. Using the EPA Clean Air Markets Division database, the investigators calculated rolling SO2 outlet averages for periods of 3 hours, 24 hours, and 30 days. These averages excluded periods of startup or shutdown. These data were used in conjunction with monthly fuel use reported to the Energy Information Agency (EIA) of the Department of Energy (DOE), allowing investigators to calculate the monthly average of SO2 removal efficiency for wet FGD equipment. This exercise was repeated for dry FGD process equipment and is discussed in a subsequent section of this report. The authors offer the following observation:

".....none of these 'top performing' wet FGD systems was able to achieve a removal efficiency of 98% or greater in every month of the year."

The authors note some of the inability to achieve 98% removal was due to the predominant use of low sulfur coal by the ten lowest SO2 emitting units and the process challenges presented by low inlet SO2 content. The "floor" of 0.06 lbs/MBtu recognizes the difficulties inherent in attaining high SO2 removal percentages for coals of lower sulfur content. However, the units considered are the top ten performing units in the U.S. – not a random sample. This data set demonstrates that the ten best performing units could not achieve 98% SO2 removal in each month of a year. And because the data set described by Weilert indicates that the best-performing wet FGD units are unable to achieve annual average reduction levels of more than perhaps 95 or 96% SO2 removal, then all wet FGD units (including those at plants burning higher sulfur coals) may be unlikely to be able to achieve monthly or annual removal levels of more than approximately 95%.

<u>Evaluated Per Ton Removal Cost</u>. Cost assumptions play a significant role in the IPM modeling done by EPA. One measure of the influence of cost assumptions can be deduced from comparing SO2 removal cost per ton ($/ton) using both the S&L-derived and UARG cost premises. To do this, one can determine the SO2 removal cost for a range of reference units that were described in the S&L study. For example, one can evaluate the SO2 removal costs for a (a) 500 MW unit, with plant heat rate of 10,000 Btu/kWh, and coal sulfur content of 3 lbs (as SO2) /MBtu; (b) 100 MW unit operating at a lower capacity factor more typical of smaller, perhaps higher heat rate units; and (c) 500 MW unit firing low sulfur (e.g., Powder River Basin (PRB)) coal. Calculations were conducted for a process capital recovery factor of 11.3% and SO2 removal of 95-98%. For a 500 MW unit operating at an 80% capacity factor and 98% SO2 removal, the SO2 removal costs derived with the S&L

premises would be \$715/ton; the costs derived with the UARG premises would be \$645/ton, a difference of approximately 10%. For a 100 MW unit operating at a 60% capacity factor and 98% SO2 removal, the SO2 removal costs are approximately \$1,450-1,575/ton, again with S&L premises deriving 10% higher costs. For a 500 MW plant operating at an 80% capacity factor and 95% SO2 removal, and firing PRB of 1.2 lbs SO2/MBtu, the removal cost is approximately \$1,750-1,950/ton, with S&L premises deriving 10% higher costs. These projected costs would be about 20% higher if a capital recovery factor reflecting the typical 15-20 year life for retrofit equipment were used, instead of the EPA-proposed value (0.113) that is appropriate for new generation.

In summary, the S&L projected capital costs somewhat exceed those costs recently projected by UARG, but both the S&L projected fixed and the S&L projected variable operating costs are similar to UARG estimates. The net influence on calculated SO2 removal costs per ton – for the same reference unit, operating conditions, and financial premises – is that the S&L estimates are approximately 10% higher than the UARG estimates.

Dry FGD

<u>Estimated Cost.</u> The projected capital cost for dry FGD process equipment, including a fabric filter for particulate matter removal, is shown in Figure 2, depicting capital cost (\$/kW) as a function of generating capacity. The S&L projected costs – depicted as the blue line through square calculated data points - are compared to capital costs for similar equipment reported in the 2010 UARG survey. Figure 2 shows a red curve-fit through a locus of cost data that represent both (a) actual costs incurred for units operating or under construction (triangle green points), or (b) estimates of costs based on detailed engineering studies (diamond blue points). Figure 2 shows S&L projected dry FGD capital costs that exceed the costs reported to UARG by plant owners by approximately 20% for smaller and 40% for larger units.

Typically the maximum processing capacity of dry FGD equipment installed to date – and that expected for dry FGD equipment in most future applications – is approximately 400 MW. It is not clear why S&L and reported UARG costs diverge at generating capacities larger than about 400 MW. The data can be interpreted in two ways. First, either there is an economy-of-scale with larger generating capacities that S&L estimates do not recognize; or second, there are design complications at larger capacities that UARG data do not recognize. Although this point is not overtly stated in the background documents, S&L may have developed the dry FGD process design for units of 500 MW capacity and greater by utilizing two spray dryer absorbers in parallel. This process design would decrease economies of scale and elevate capital cost at higher capacities.

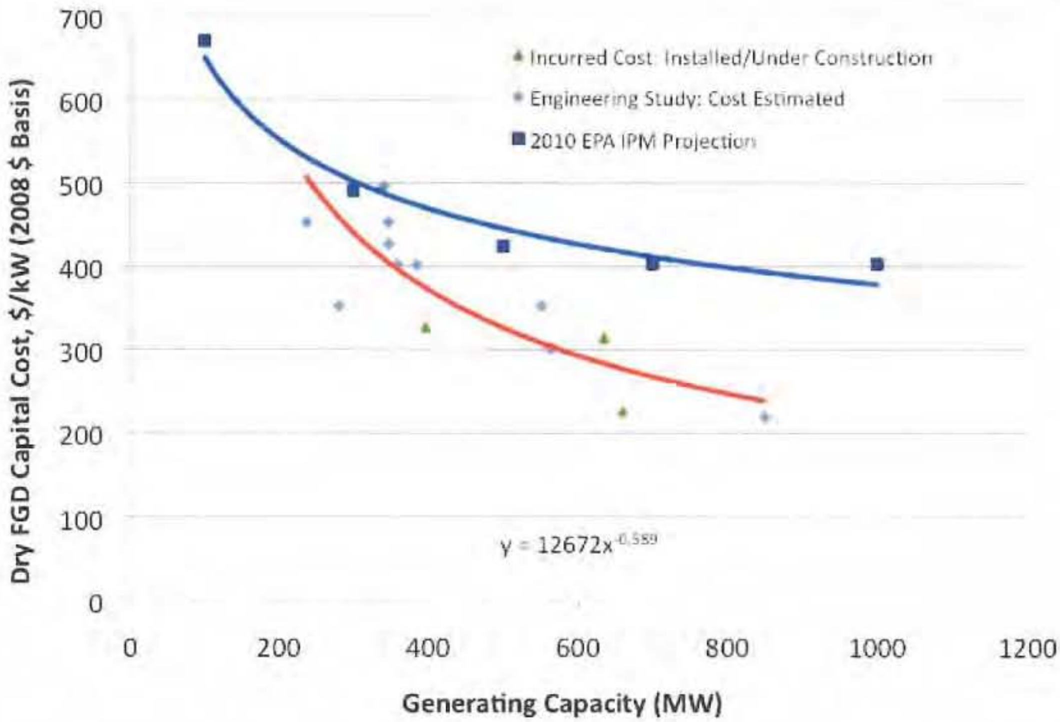

Figure 2. EPA-IPM Input for Dry FGD Capital Cost vs. UARG Survey Data

It should be noted Figure 2 contains actual incurred costs for only three units; the remainder are projections.

Fixed and variable operating costs for dry FGD process equipment were also projected by S&L. The fixed operating costs are essentially identical to UARG estimates. S&L projected variable operating costs for a specific coal (2 lbs SO_2/MBtu); this variable cost of 2.60 mills/kWh is a factor of two higher than the 1.1 mills/kWh cost determined in the UARG study for PRB coal. One contributor to the difference in cost estimated by S&L are assumptions of cost for lime reagent and for solid byproduct disposal. S&L's estimate of the delivered cost for lime appears higher than historical values ($95/ton compared to historical values of $60/ton) but could be representative of lime reagent costs in the future. Given the uncertainty in solid byproduct disposal costs and challenges in siting a landfill, it is possible that S&L's estimate of byproduct management costs could be realized.

In summary, the S&L projected capital costs for dry FGD exceed those recently projected by UARG, and S&L's fixed and variable operating cost estimates are notably higher than UARG's estimates. This will elevate the calculated cost per ton of SO_2 removed for dry FGD, and perhaps reduce its role as an alternative to wet FGD.

SO2 Removal Assumption. The S&L analysis assumes 95% SO2 removal by dry FGD equipment, based on an annual average, with a minimum "floor" SO2 emission rate of 0.08 lbs/MBtu. Weilert (2010) evaluated the SO2 performance capabilities of dry FGD using an approach similar to that used to evaluate wet FGD process equipment. Weilert identified the lowest ten SO2 emitting units equipped with dry FGD and calculated rolling averages of SO2 outlet emissions on a 3-hour, 24-hour, and 30-day basis. These SO2 data were used in conjunction with fuel input data reported to the EIA to calculate SO2 removal on a percentage basis. Weilert concludes the data set does not support a 95% SO2 removal efficiency in each month of the year, based on the coals used in the ten units examined. Although this point is not explicitly addressed, the data from the plants evaluated by Weilert suggest it may be possible to achieve a 93% SO2 removal efficiency on an annual basis. Similar to the case of wet FGD, however, the data set evaluated by Weilert is not representative of industry practice. The units represent only the top ten performing units in this category, *i.e.*, those units that are already achieving low outlet values of SO2. Thus, many dry FGD units are unlikely to be able to achieve monthly or annual removal levels of as much as 93%.

CONTROL EQUIPMENT FOR NOx

NOx control process equipment -- selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and combustion controls -- are addressed in these analyses.

Selective Catalytic Reduction (SCR)

Estimated Cost. The specifics of the cost evaluation for SCR are described in a document prepared by S&L (EPA, 2010d).

The capital costs for SCR process equipment as projected by S&L are shown in Figure 3, depicting capital costs ($/kW) as a function of generating capacity. Figure 3 presents data sets or curve-fits of data sets for three sources of SCR costs. S&L's projected capital costs are described by the blue line that is curve-fit through blue square data points, which reflect the 2010 IPM update described by EPA (2010d). This curve is labeled "2010 EPA IPM Projections". The red curve-fit through the locus of red square points represents capital costs for SCR process equipment as reported in the 2010 UARG survey. This curve is labeled "2008-2010 Operating Units", noting all cost data representing units at which the SCR became commercially operational in that timeframe. Finally, the gray curve reflects SCR costs projected by EPA in 2004 (Khan, 2004). This curve was derived in 2004, but used in the 2006 IPM analyses, and is thus labeled "2006 EPA IPM Projections".

It is not clear why the S&L SCR capital cost estimates are 20-25% lower than recent UARG-derived costs. Perhaps part of the reason for the difference is that S&L

determined installed capital cost by applying a cost multiplier, with a subjective degree of retrofit difficulty, to estimated process capital. The approach of using retrofit difficulty factors to assess installed cost, although widely used, is known to provide faulty cost estimates, particularly for SCR. SCR cost estimates using retrofit difficulty factors are particularly prone to error as such factors frequently do not capture the true complexity of a site, or the limitations on productivity of installation labor in a constrained (e.g., sellers') market. S&L also stated that actual incurred SCR costs were used in the analysis reported by the Midwest Ozone Group in a document submitted to the Lake Michigan Air Directors Consortium (Marchetti, 2007). The SCR capital costs contained in that referenced document, however, reflect installations prior to 2006, and not the most recent installation window. Thus, S&L costs may be influenced by 2006-vintage experience.

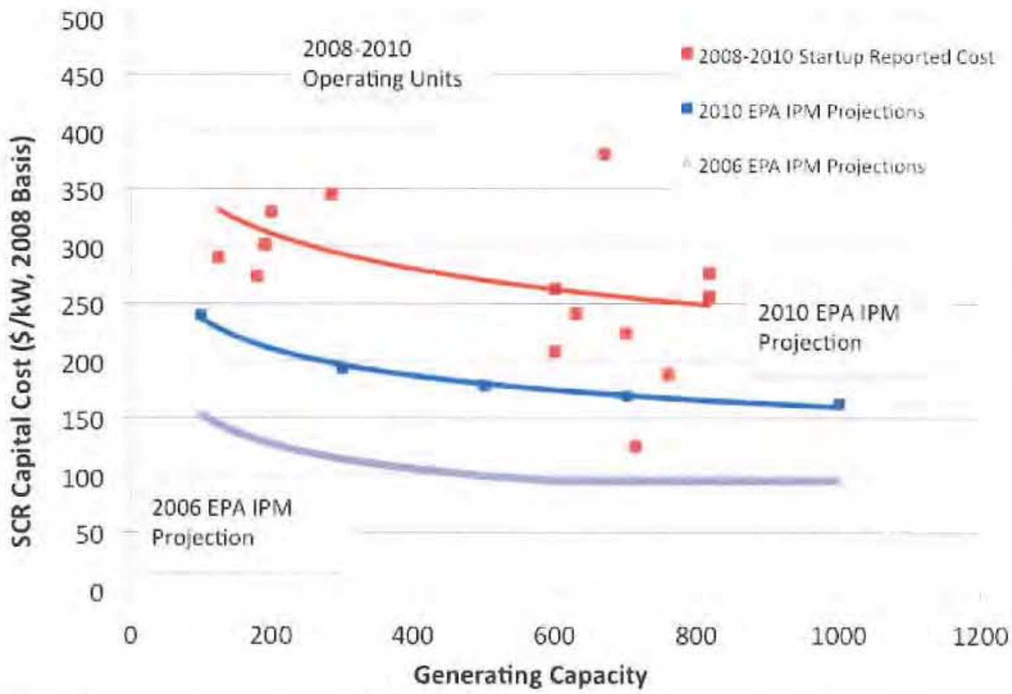

Figure 3. EPA-IPM Input for SCR Capital Cost vs. UARG Survey Data

S&L estimates of fixed O&M costs are similar to those in the UARG analysis. The S&L analysis projects SCR fixed O&M costs to be $2.5/kW-yr for a 500 MW unit; UARG's estimate of 0.75% of process capital for a 500 MW unit (requiring a capital cost of $265/kW) translates into an equivalent cost of about $2.1/kW-yr.

Variable O&M costs projected by S&L for SCR are 1.1-1.3 mills/kWh. The UARG analysis estimates the variable O&M costs to be 0.67-1.3 mills/kWh; however, the variable O&M costs in the UARG estimates that are most relevant to the coal and boiler NOx emissions used for the S&L reference case are in the range of 0.77-0.90

mills/kWh. The differences in these operating costs – at most about 10% - are likely due to the delivered price of both reagent and replacement catalyst, and the frequency of catalyst exchange.

NOx Control Performance. Recognizing that there is a limit to the lowest NOx emission rate that can be achieved with SCR, the S&L analysis recommends the establishment of NOx emission rate "floors" with use of SCR. S&L assumed NOx outlet emissions cannot be less than 0.05 and 0.07 lbs/MBtu, respectively, for sub-bituminous and bituminous coals. It is possible that these "floors" may represent minimum emission rates that are achievable over short-term averaging periods for high-performing SCRs at certain units, although SCRs at other units may not be capable of achieving rates that low.

Evaluated Per Ton Removal Cost. One measure of the influence of cost assumptions is to compare the NOx removal cost per ton ($/ton) using both the S&L-derived and UARG cost premises. The NOx removal cost was determined for a reference unit described in the S&L study documentation: a 500 MW unit, with a plant heat rate of 10,000 Btu/kWh, and a boiler NOx emission rate of 0.40 lbs/MBtu (typifying NOx emissions from burning bituminous coal). Calculations were conducted for an 80% capacity factor, a process capital recovery factor of 11.3%, and NOx control to 0.07 lbs/MBtu (83% NOx removal). The NOx removal costs derived with the S&L premises ($2,552/ton) are about 18% less than those derived with UARG premises ($3,117/ton). The most significant source of the differences in evaluated cost using S&L versus UARG-reported premises is the difference in capital requirement. Similar to the case with wet FGD, projected costs for SCR installations would be approximately 20% higher if one used a capital recovery factor reflecting the typical 15-20 year life for retrofits to existing units, instead of the value proposed by EPA (0.113) that is appropriate for new generation.

In summary, the S&L-projected capital costs for SCR are notably less than those recently projected by UARG. S&L and UARG fixed O&M costs are similar, but S&L's variable O&M costs are higher than those UARG derived from discussions with plant owners. Based on these differences in cost estimates, using the S&L SCR cost premises generates a calculated NOx removal cost per ton that is about 18% below that derived with UARG premises, for the same reference unit, operating conditions, and financial premises.

SNCR

S&L estimate that the SNCR capital cost for units less than 300 MW will be $45/kW. This number is consistent with, although generally somewhat higher than, the cost derived by UARG of $20-45/kW for units less than 300 MW. Variable O&M costs of about 1 mills/kWh are projected by S&L. These costs are similar to UARG's estimates of variable O&M costs, which -- depending on unit size and initial NOx emission rate -- are 0.5-1 mills/kWh. For most applications the variable O&M costs are anticipated to be near the higher end of the UARG estimated range. Fixed O&M costs for SNCR are negligible.

S&L assume SNCR control efficiency to be 25%, similar to UARG projections. S&L also limit the application of SNCR to 100-300 MW at this NOx removal capability. (UARG's projections permit applying SNCR to larger units, but estimate that NOx removal at those units would be restricted to less than 25%.)

Combustion Controls (Low NOx Burners)

S&L estimates the capital cost of low NOx burners (LNB) to be $24-45/kW, depending on the generating capacity of the boiler to which the LNB is retrofit. These estimates are accepted as reflecting recent industry experience. UARG-derived estimates of LNB costs average $20/kW; for a 300 MW unit, the UARG $20/kW estimate approximates S&L's $24/kW estimate. S&L also assign a small fixed cost and variable cost to the operation of this equipment.

ROLE OF SMALL UNITS

EPA predicts generating units that are less than about 200 MW in size will install SO2 and NOx controls. Specifically, EPA projects that 15 units of less than 225 MW will install FGD, and that 6 units of less than 220 MW will choose to install SCR. To date, the number of generating units in the U.S. of this capacity that have deployed either conventional FGD or SCR is small. The smallest generating units with SCR are the 80 MW Dahlman units at City of Springfield Power & Light. The smallest with FGD are the dry-FGD-equipped 57 MW Cogentrix units. These units were retrofit with control technology at a time when demand for such systems was low – i.e., a buyers' market. The reported costs for these units – such as $175/kW for the 80 MW Dahlman units – are unlikely to be replicated in the anticipated market for 2012 and 2014 compliance.

S&L recognize that retrofitting SCR and FGD to units less than about 200 MW capacity would be prohibitively costly. S&L suggest that in light of this cost penalty, the owners of such units would choose to retrofit an alternative control option such as that recently tested in a DOE-funded demonstration (Connell, 2009). S&L propose the cost for this alternative option to be lower than the cost associated with retrofitting SCR or FGD. S&L do not have data to derive a cost algorithm for this alternative control technology, but propose a means to approximate such costs. Specifically, S&L propose to use the cost algorithm developed for FGD and SCR; however, S&L use a higher capacity to assign the cost per unit ($/kW) generating capacity. S&L state that the absolute magnitude of capital cost ($M) for SCR and FGD for a 100 MW unit – when using a 200 MW basis to derive unit cost ($/kW), and using 100 MW to calculate the actual cost magnitude ($M) – by coincidence provides about the right cost estimate for this scenario. Although this approach is imperfect, S&L submit that the approach permits a reasonable cost number to be used in IPM while still recognizing that SCR and FGD will likely not be applied to 100 MW units.

S&L are correct in recognizing that the cost to retrofit SCR and FGD on small units is prohibitive and thus that owners of smaller units might well choose to retire units rather than retrofit them with any additional controls. This is particularly the case as long as alternative NOx and SO2 control options are few and are offered by only one or two suppliers (and those suppliers have little experience in installing the alternative technologies). Such options might be applied in isolated cases but broad deployment within the mandated time frame is unlikely.

SUMMARY

EPA has revised the cost inputs for IPM based on information prepared by a knowledgeable architect/engineering company: Sargent & Lundy Engineers (S&L). EPA has also derived control technology costs based on an S&L database of component costs and installation charges. This report has compared the capital and operating costs derived from the newly-compiled work by S&L with the capital and operating costs summarized by UARG in a recent survey of costs incurred by power plant owners that have installed similar control technologies (UARG, 2010). This report also has evaluated information presented by S&L concerning the performance of various control technologies for reducing SO2 and NOx. The following is a summary of this report's findings.

The S&L-projected capital costs associated with installing wet FGD systems can be 20-25% higher than the capital costs for FGD installations as estimated by UARG. S&L's estimates of fixed and variable operating and maintenance costs are generally similar to those summarized by UARG. The S&L analysis assumes wet FGD systems can achieve an annual average SO2 removal capacity of 98%, with a "floor" of 0.06 lbs/MBtu. A detailed statistical study by Weilert (2010), however, suggests that, at least when burning lower sulfur coals, even the best-performing units cannot achieve 98% SO2 removal over long averaging times (*e.g.*, months or a full year). The data were not evaluated to determine the annual average; but for the units addressed it is possible the annual SO2 reduction would be limited to 95 or 96%.

For dry FGD, the S&L-derived capital and operating costs are both higher than UARG's estimated costs, with the former most divergent for large generating capacity. S&L propose a dry FGD annual SO2 removal target of 95% with a "floor" of 0.08 lbs/MBtu. The recent analysis of the SO2 emissions control performance data from dry FGD operating at the ten lowest SO2-emitting units in the U.S. (Weilert, 2010) shows that 95% removal efficiency could not be achieved. The data were not evaluated to determine the annual average; but for the units addressed it is possible the annual SO2 reduction would be limited to about 93%.

The S&L estimates of the evaluated cost of SCR NOx control – on a $/ton basis of NOx removed – are approximately 20% less than the evaluated cost reported to UARG by owners that installed SCR systems in the past three years. Most of this difference is due to lower estimates of capital cost, which can be 20-25% less than costs reported by owners. The S&L-estimated operating costs for SCR systems exceed those estimated by UARG by not more than 10%. As far as SCR performance is concerned, the S&L analysis recognizes that there is a limit to the lowest NOx emission rate that can be achieved with SCR. S&L assumed NOx outlet emissions cannot be less than 0.05 and 0.07 lbs/MBtu, respectively, for sub-bituminous and bituminous coals. These performance levels may represent minimum emission rates over short-term averaging periods for certain high-performing SCRs, but SCRs at other units may not be capable of achieving rates that low, particularly over longer averaging times.

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Docket ID No. EPA-HQ-OAR-2009-0491-2756.1

COMMENTS OF THE UTILITY AIR REGULATORY GROUP

on the

PROPOSED FEDERAL IMPLEMENTATION PLANS TO REDUCE INTERSTATE TRANSPORT OF FINE PARTICULATE MATTER AND OZONE (PROPOSED AIR POLLUTION TRANSPORT RULE)

75 Fed. Reg. 45210 (Aug. 2, 2010); Docket ID No. EPA-HQ-OAR-2009-0491

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October 1, 2010

TABLE OF CONTENTS

I. Introduction. 4

II. UARG Agrees with Certain Aspects of the Proposed Transport Rule. 5

- A. EPA's Proposal, in Its Preferred Remedy Option, To Allow Some Degree of Interstate Allowance Trading. 5
- B. Permitting Banking of Allowances Beginning in the First Year of the Program. 7
- C. EPA's Decision Not To Auction Allowances Under the Proposed Remedy Option. 10

III. The Proposed Transport Rule Should Not Include an Initial Compliance Deadline of 2012. 11

- A. An Initial Compliance Deadline of 2012 Will Not Allow Enough Time for Sources To Make the Changes Necessary To Comply with the Transport Rule, or for States To Develop Implementation Plans. 12
- B. A Compliance Deadline in 2012 Is Neither Necessary Nor Appropriate. 14

IV. The Proposed Transport Rule Would Unlawfully Supplant the Role of States Under the Act. 19

- A. EPA Has No Authority To Promulgate a FIP To Replace CAIR. 19
- B. EPA Lacks Authority To Impose Any Unit-Specific Emission Rate Limits -- Such as the Limits in the Direct Control Remedy Option -- Under Section 110(a)(2)(D)(i)(I). 27

V. The January 2012 and January 2014 Compliance Deadlines Set Forth in the Proposed Transport Rule Are Unreasonable and Unrealistic. 27

- A. Background. 31
  1. Step One Requires More Than Conducting an Engineering Review. 32
  2. A Construction Permit Is Only One of the Many Authorizations that Affected Plant Owners May Need. 34
  3. The Actual Construction of FGD and SCR Systems at Existing Sites Will Take Longer than EPA Suggests. 37

B. EPA Relies Upon Incomplete and Outdated Information in Concluding that FGD and SCR Retrofits Can Be Installed in a Total of Less than 30 Months. 38

C. FGD Installations: Real-World Examples Demonstrate that EPA Has Substantially Underestimated How Long It Typically Takes To Retrofit FGD Systems at Power Plants. 41

D. SCR Installations: Real-World Examples Demonstrate that EPA Has Substantially Underestimated How Long It Typically Takes To Retrofit SCR Systems at Power Plants. 44

E. Summary and Conclusions. 46

VI. EPA's Analysis Significantly Understates the Amount of Electric Generating Capacity that Would Have To Undergo FGD and SCR Retrofits in the 2012-2014 Period and the Associated Demands on Resources; Constraints on Labor Resources Make Compliance With the PTR's Timeline Impossible 48

VII. Many of the Judgments and Policy Decisions Underlying the Structure of the Proposed Transport Rule Are Inappropriate and Unjustified. 50

A. EPA's Base Case Modeling Should Have Included CAIR 50

B. EPA Should Return to Its "Monitored-Plus-Modeled" Approach 53

C. EPA's Proposed Air Quality Contribution Threshold Is Flawed 55

D. The Method EPA Used To Determine "Interference With Maintenance" in the Proposed Rule Overestimates Actual Future Design Values 57

E. The Process EPA Used To Classify Certain States as "Group 1" States Is Inadequately Explained and Misguided. 61

F. EPA's Determinations of "Significant Contribution" and "Interference with Maintenance" Improperly Presuppose Upwind-State EGU Emissions as the Primary Cause of Downwind Nonattainment Problems and Inappropriately Underestimate the Contribution of Local Sources from a Variety of Emission Sectors 64

1. EPA's Approach Places an Undue and Unlawful Burden on Sources in Upwind States To Reduce Emissions. 64

2. EPA's Air Quality Assessment Improperly Overestimated the Marginal Benefit of Emission Reductions Above Relatively Low Dollar-Per-Ton Levels. 66

G. EPA Has Failed To Explain Why It Did Not Use 2008 Heat Input Data in Calculating SO2 Emission Budgets. 73

VIII. EPA's Use of Inaccurate Inputs and Assumptions for -- and Unrealistic Outputs from -- EPA's Use of the Integrated Planning Model Makes the Proposed Transport Rule Inadequate for Public Comment. 75

A. Many of the IPM Inputs for Individual Units Are Inaccurate. 77

B. EPA's IPM Outcomes Do Not Reflect Actual Source Operations. 80

IX. Certain EPA Assumptions and Determinations Do Not Account Adequately for the Interaction Between the Proposed Rule and Other CAA Programs. 85

A. Contrary to EPA's Assumption, Permitting Requirements Cannot Be Expected To Be Met in Time To Satisfy the Proposed Transport Rule's Compliance Schedule 85

B. EPA Should Provide Justification for Its Unsupported Assertion that It Is "Very Unlikely" that Pollution Control Projects Would Cause GHG Emission Increases in Excess of the PSD Emission Thresholds in the Agency's June 2010 GHG Tailoring Rule. 86

X. EPA Should Amend the Proposed Transport Rule To Allow for Increased Flexibility in Compliance and Allowance Trading 87

A. The Variability Limits and Assurance Provisions Proposed by EPA Are Unduly Stringent and Should Be Adjusted. 87

1. Variability Limits. 87

2. Assurance Provisions. 89

B. Units Should Be Permitted To Borrow Allowances From Future Year Allowance Accounts, at Least on a Limited Basis. 90

C. EPA Should Not Establish Any Government-Run Allowance Auctions. 90

XI. Requirements for Electronic Reporting of Quarterly Reports 91

A. Electronic Reporting Format 91

B. Adjustments to Certified Information by the Administrator 94

C. Correction and Resubmission of Quarterly Reports 94

XII. As a Matter of CAA Procedural Requirements, the Proposed Rule's Unfounded Assumptions, Errors, and Apparent Anomalies -- and EPA's Failure To Explain Adequately Critical Aspects of the Proposal and To Include in the Docket Information that Would Enable Replication of EPA's Process -- Make the Proposed Rule Inadequate for Public Comment. 96

XIII. Conclusion. 98

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on the
PROPOSED FEDERAL IMPLEMENTATION PLANS TO REDUCE INTERSTATE TRANSPORT OF FINE PARTICULATE MATTER AND OZONE

75 Fed. Reg. 45210 (Aug. 2, 2010); Docket ID No. EPA-HQ-OAR-2009-0491

October 1, 2010

On August 2, 2010, the U.S. Environmental Protection Agency ("EPA" or the "Agency") published its Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone; Proposed Rule ("Proposed Transport Rule" or "PTR") and announced a 60-day public comment period on the proposal, ending on October 1, 2010. 75 Fed. Reg. 45210/1 (Aug. 2, 2010). The Utility Air Regulatory Group ("UARG") submits the following comments on the Proposed Transport Rule. UARG is a voluntary, not-for-profit group of electric utilities, other electric generating companies, and national trade associations. UARG's purpose is to participate on behalf of its members collectively in EPA rulemakings under the Clean Air Act ("CAA" or "Act") and other proceedings that affect the interests of electric generators and in related litigation. Because the Proposed Transport Rule specifically -- and exclusively -- targets nitrogen oxide ("NOx") and sulfur dioxide ("SO_2") emissions from electric generating units ("EGUs") for regulation, UARG and its members have a compelling interest in the present rulemaking.

UARG submits these comments against a background of Agency decisions that has made participation in this proceeding exceedingly difficult. Specifically, on September 1, 2010, EPA published a separate Notice of Data Availability ("NODA") for the Proposed Transport Rule. 75 Fed. Reg. 53613. The NODA announces additional EPA modeling runs and other information that "EPA proposes to use to support the final rule," as well as "a list of further planned updates to support the final rulemaking." *Id.* EPA announced a *separate* comment period for the

NODA, extending until October 15, 2010 (and may have separate comment periods for other subsequently posted information), but refused to extend the comment period for the underlying proposal. EPA's decision to maintain two separate deadlines for public comments -- one on the Proposed Transport Rule and the information posted in the docket contemporaneously with it, and another for the information released pursuant to the NODA -- makes it extraordinarily challenging to provide comprehensive comments on EPA's proposal. In addition, EPA on September 10, 2010, denied UARG's August 19, 2010 request for an extension of the comment period on the Proposed Transport Rule to November 30, 2010, and did not respond to a September 10, 2010 UARG request for a comment deadline extension to November 30, 2010, for both the proposed rule and the NODA.[1] In light of the significant differences between the data on which EPA based (or says it based) the proposed rule and the data EPA released later pursuant to the NODA, EPA should withdraw the Proposed Transport Rule, revise it using whatever data EPA deems most appropriate (and addressing the proposed rule's many other deficiencies as discussed in these comments) and republish it for public comment with an adequate comment period.

The Proposed Transport Rule is intended to replace the Clean Air Interstate Rule, 70 Fed. Reg. 25162 (May 12, 2005) ("CAIR"), which EPA promulgated in 2005 and the U.S. Court of Appeals for the D.C. Circuit found to be "fundamentally flawed," initially vacated and remanded to the Agency in 2008, and then allowed to remain in place pending completion of EPA's remand rulemaking. *See North Carolina v. EPA*, 531 F.3d 896, 929 (D.C. Cir. 2008), *modified on petitions for rehearing*, 550 F.3d 1176 (D.C. Cir. 2008). Like CAIR, the Proposed Transport Rule primarily addresses EGUs and is based on EPA's interpretation and application of section

[1] UARG incorporates its August 19, 2010 and September 10, 2010 letters herein by reference.

110(a)(2)(D)(i)(I) of the Act, which requires, in relevant part, each state's plan for attaining the national ambient air quality standards ("NAAQS") to "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]."

The Proposed Transport Rule is structured as a federal implementation plan ("FIP") and would regulate emissions from EGUs in 32 states. 75 Fed. Reg. at 45210/1. According to the proposal, EPA plans to promulgate a final rule in spring 2011,[2] imposing an initial compliance date of January 1, 2012 (May 1, 2012 for the ozone season[3] NOx program), and a further SO_2 reduction requirement on January 1, 2014, for many states (which EPA calls "group 1" states) subject to the program. 75 Fed. Reg. at 45213/2, 45215/3.

UARG notes that it plans to file additional comments on EPA's September 1, 2010 NODA and on any subsequently published EPA updates to support the final rulemaking. Because the information in the NODA is inextricably linked with information in the PTR, some

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[2] Although the Proposed Transport Rule states only that EPA anticipates publishing a final rule in "spring 2011," *see, e.g.*, 75 Fed. Reg. at 45213/2, the Agency has announced that it anticipates taking final action in the rulemaking in June 2011. *See, e.g.*, EPA, Proposed Air Pollution Transport Rule -- "Overview Presentation 7/26/2010," at slide 29 (July 26, 2010), *available at* http://www.epa.gov/airquality/transport/actions.html.

[3] EPA requests comments on whether the ozone season should be longer than the five-month season used in the NOx SIP Call rule, 63 Fed. Reg. 57356 (Oct 27, 1998), and CAIR (May 1 through September 30), perhaps to correspond to the ozone monitoring season for each state. 75 Fed. Reg. at 45292/1. UARG does not believe EPA has provided an adequate basis for expanding the ozone season for purposes of this rule, however, if EPA expands the ozone season for some or all states, it would need to consider carefully how such an expansion would affect the proposed program, and at a minimum would have to increase the NOx ozone season budgets in proportion to the additional time in the season for affected states. Any such change should be addressed in a supplemental notice of proposed rulemaking.

of UARG's comments on the PTR necessarily relate to information associated with the NODA and UARG's comments on the NODA will be relevant to the PTR.

I. Introduction.

EPA's task in developing this proposed rule was to remedy the deficiencies identified by the court in *North Carolina v. EPA*. To an extent, EPA appears to have attempted to discharge that obligation. Indeed, as discussed in section II of these comments, UARG agrees with certain aspects of the proposal. For example, UARG supports EPA's preferred option of permitting some degree of emission allowance trading (although, as discussed subsequently in the comments, UARG urges EPA to consider expanding the margin for trading).

Yet in other respects, EPA's proposed approach is seriously misguided. The decision to impose FIPs rather than allow states time to develop state implementation plans ("SIPs") to implement section 110(a)(2)(D)(i)(I) obligations rests on an unlawful view of the CAA and the federal-state cooperative relationship under the Act. The PTR's compliance schedule is wholly unreasonable, particularly its imposition of a January 1, 2012 initial compliance deadline that will fall only a few months after EPA plans to take final action in this rulemaking. EPA has failed to propose a defensible methodology for determining statewide emission reduction obligations and has required additional emission reductions even where they have not been shown to be needed to meet the air quality objectives that EPA asserts. And EPA in this proposed rule has arrogated to itself, in contravention of the law, the right and responsibility to determine *how* a state's emission reduction requirements must be accomplished, thereby assuming an exceptionally heavy burden to show that it has applied its unit allowance allocation methodology accurately and consistently. Review of the PTR's supporting information, however, reveals that EPA's approach on this score is anything but accurate and consistent. Moreover, in many respects, EPA's explanation of the elements of the PTR, and its information and calculations offered in support of the PTR, are opaque to the point of incomprehensibility. These points are explained further below.

For these reasons, UARG believes that the PTR is inadequate as a proposed rule to replace CAIR. EPA should develop and offer for comment a new proposal that corrects the serious flaws in the PTR.

II. UARG Agrees with Certain Aspects of the Proposed Transport Rule.

UARG understands that development of a replacement rule for CAIR that properly responds to the court's decision in *North Carolina v. EPA* is in some respects a challenging task. Although, as discussed above and in the following sections of these comments, the proposed rule contains a number of serious flaws that must be remedied before EPA could continue with this rulemaking, UARG agrees with and supports certain aspects of the PTR. These include (i) the proposal to permit some degree of interstate allowance trading, (ii) the proposal to permit allowance banking beginning in the first year of the program, and (iii) the proposal not to auction allowances (in the proposed interstate trading remedy).[4] UARG discusses these points below, along with some suggestions to further strengthen these elements of the proposed rule.

A. EPA's Proposal, in Its Preferred Remedy Option, To Allow Some Degree of Interstate Allowance Trading.

EPA's Proposed Remedy Option allows limited interstate allowance trading, while its two alternative options would not allow any interstate trading. UARG supports EPA's proposal to permit at least some degree of allowance trading. Permitting interstate allowance trading would provide for increased flexibility and permit more cost-effective compliance options. Increased flexibility will be particularly important in the early years of the program, especially if

[4] As discussed below, UARG opposes the proposed allowance auction feature of the proposed Intrastate Trading Remedy Option (and indeed opposes that remedy option altogether).

EPA does not change the proposed rule's unreasonably accelerated compliance schedule as suggested in these comments.

UARG believes that the interstate trading program described in the proposal should resolve the problems with the CAIR program's unrestricting trading that the court cited in *North Carolina v. EPA*. The court held that the CAIR interstate trading program was inconsistent with the Act, based mainly on the program's region wide approach. Noting that "EPA is not exercising its section 110(a)(2)(D)(i)(I) duty unless it is promulgating a rule that achieves something measurable toward the goal of prohibiting sources 'within the State' from contributing to nonattainment or interfering with maintenance 'in any other State,'" the court held that "EPA's apportionment decisions have nothing to do with each state's 'significant contribution.'" 531 F.3d at 907. Although the Proposed Transport Rule is flawed for reasons discussed elsewhere in these comments, the Proposed Remedy Option incorporates a mechanism for addressing the significant contribution of individual states to downwind nonattainment and maintenance problems.

In developing the Proposed Transport Rule, EPA used photochemical source apportionment modeling to identify the impact of emissions *from specific upwind states* on downwind areas projected to be in nonattainment or to have maintenance problems in 2012. 75 Fed. Reg. at 45253/1. Then, EPA determined *each state's* significant contribution to nonattainment and interference with maintenance based on the emissions that EPA projected could be eliminated from that state for a specific cost (in dollars per ton of reduced emissions), in conjunction with an analysis of air quality benefits at various cost levels, and set state budgets accordingly. 75 Fed. Reg. at 45271/1-2. Thus, although UARG disagrees with many aspects of the data and methodology that EPA used in this analysis, EPA's methodology does, as a general matter, attempt to address the EPA-projected contribution to nonattainment and interference with maintenance in downwind states from emissions from particular upwind states. At least in broad terms, the PTR's focus on state-specific data should align with the court's characterization of states' section 110(a)(2)(D)(i)(I) duties.[5]

In addition, if EPA retains its proposed two-phased compliance schedule,[6] UARG supports EPA's proposal not to apply variability limits and assurance provisions before 2014. 75 Fed. Reg at 45296/1, 45305/3. EPA states that assurance provisions will not be necessary to limit interstate trading during the first two years of the program because during those years, "state-specific budgets are based on known air pollution controls and thus a high level of certainty exists about where reductions will occur." 75 Fed. Reg. at 45306/1. Given the nature of EPA's proposal, EPA's reasoning is sound: If the state budgets are based on reductions that EPA expects will occur based on use of control equipment that will be installed and operational by that time, there is no need for assurance provisions during this time period.[7]

B. Permitting Banking of Allowances Beginning in the First Year of the Program.

The Proposed Transport Rule properly recognizes the important environmental and economic benefits of allowance banking, a feature of CAIR that was not challenged in the litigation on that rule and that the court's opinion in no way undermines. The ability of sources

[5] Furthermore, as the court recognized, although North Carolina challenged the CAIR interstate trading program, North Carolina did not argue -- and the court did not hold -- that interstate trading was per se unlawful. *North Carolina*, 531 F.3d at 906.

[6] EPA has not justified its proposed compliance schedule and should not, for example, impose an initial compliance deadline as early as 2012. *See* section III *infra.*

[7] However, as explained elsewhere in these comments, many of EPA's assumptions regarding which controls will be installed and operational by the beginning of 2012 are ill-founded. EPA thus should revise its calculations based on an accurate accounting of the controls that will be operational by the beginning of 2012, if EPA retains the 2012 deadline.

to use banked allowances for compliance with the program encourages them to make early emission reductions to the extent that cost-effective early reductions are possible. Unfortunately, the nature and stringency of the proposed rule's emission reduction requirements and its proposed compliance schedule would make it very difficult for most sources to make extra emission reductions during the early years of the program. *See* sections III and V *infra* for UARG's comments on the compliance schedule. Permitting allowance banking in conjunction with an adjustment to the compliance schedule that would allow sources adequate time to comply with the program (and that would give states adequate time to develop SIPs) could well result in greater amounts of early emission reductions and, most likely, greater emission reductions over the long run.

UARG also emphasizes, however, that it supports approaches that would permit the use of banked CAIR NOx allowances for compliance with the Proposed Transport Rule. In the final rule, EPA should provide that it will transfer all CAIR NOx annual and ozone season allowances held in each source's compliance accounts for the final compliance period of CAIR into that source's compliance accounts for the new program (to the extent the source is subject to the new program's annual or ozone season NOx requirements, or both). This could readily be accomplished because, for purposes of compliance with the new program, EPA proposes to use the same Allowance Management System ("AMS") that it used for compliance with CAIR. 75 Fed. Reg. at 45312/1. There is no reason not to allow sources to use their CAIR allowances (including allowances that they bought or otherwise acquired from others) for compliance with the new program.

EPA's concern that some may view an approach that authorizes sources to use banked CAIR NOx allowances as unfairly permitting some sources a larger share of allowances due to

CAIR's use of fuel adjustment factors, which the *North Carolina* decision found EPA had not adequately justified, is no basis to bar use of these allowances already allocated. The court's opinion in no way bars *use* of these already-allocated allowances, on a banked basis, in a new program. Moreover, if EPA disallows use of banked CAIR NOx allowances at this juncture, it will be to the detriment of *all* sources that hold banked CAIR NOx allowances at the time that CAIR expires. It would be far better to allow all sources the benefit of their banked allowances than to render them worthless at the end of the CAIR program.[8]

Indeed, there are many compelling reasons to allow sources to use their banked CAIR NOx allowances for compliance with the proposed rule. First, as noted above, nothing in the court's *North Carolina* opinion precludes -- and in fact, no party challenged -- use of banked CAIR NOx allowances. The only flaw identified by the court with respect to CAIR NOx allowances was the way EPA established NOx allowance budgets. Second, as EPA suggests, permitting use of banked CAIR NOx allowances would promote the continuation in 2010 and 2011 of the reductions that occurred under CAIR. *Id.* at 45339/1. Likewise, it would avoid creating an incentive for sources to "use up" CAIR NOx allowances, thereby potentially increasing their NOx emissions temporarily, because those allowances would -- in the absence of a provision allowing use of banked CAIR NOx allowances in the new program -- have no value after the allowance transfer deadline for the final CAIR annual and ozone season compliance periods. Third, allowing use of banked CAIR NOx allowances would provide a modest degree

[8] If EPA is concerned that the amount of banked CAIR NOx allowances is or will be so great that it may reduce the amount of emission reductions that would otherwise be achieved under the proposed rule, *see* 75 Fed. Reg. at 45339/1, there are better ways to avoid that outcome than to invalidate the allowances in whole or in part. EPA should allow sources the full benefit of their banked CAIR NOx allowances. If EPA determines that some limitations on use of those allowances are necessary, EPA should at least permit use of a substantial amount of the allowances over at least the first few years of the new program.

of increased flexibility for sources during the early years of the new program, an especially important consideration if EPA requires compliance with the Transport Rule according to the unreasonably accelerated schedule set forth in its proposal.

Indeed, the issue of use of banked CAIR NOx allowances is one example of the reasons why, EPA should design the transition to the Transport Rule as a seamless regulatory process to ensure that the mechanisms remain in place for continuous compliance and assurance of continued emission reductions. The D.C. Circuit, in its December 2008 decision, determined that CAIR could remain in place while EPA developed a replacement rule, specifically because of concerns that the emission reductions attributable to CAIR would not occur during the transition period if CAIR were vacated. Because the court allowed CAIR to remain in place, it is possible for EPA to retain aspects of CAIR that will assure full compliance and that will promote the effective and seamless transition to the new rule, without the possibility of short-term backsliding. This would also leave in place, for example, the CAIR 2015 phase II control requirements until the Transport Rule can be implemented. This approach will provide additional time for EPA to complete the current rulemaking and permit an adequate compliance schedule under the new rule, even while electric generating companies are required to continue to plan for further emission reductions to meet the CAIR 2015 deadline.

C. EPA's Decision Not To Auction Allowances Under the Proposed Remedy Option.

UARG supports EPA's proposal not to include any allowance auctioning under its Proposed Remedy Option. No need or reason exists to use allowance auctions to implement the Proposed Transport Rule's emission reduction requirements. If, however, EPA promulgates a final rule based on the Intrastate Trading Remedy Option, an option that UARG does not support, EPA should remove from that option the proposed provisions for allowance auctions. It is entirely possible to accomplish the objectives of those proposed auctions through distribution of allowances free of charge. This is particularly true if states are provided the time to develop SIPs that will allow each state to determine how best to make allocations that address that state's specific needs.

As explained in section X.C below, government auctioning of allowances is contrary to the principle that regulated sources are not subject to any obligation to emit below their allowance allocation levels established by the program. Revenues from the allowance auctions that EPA describes in the Intrastate Trading Remedy Option would be deposited into the U.S. Treasury. 75 Fed. Reg. at 45327/2. The effect of such auctions, in which proceeds accrue to the government, is to force affected sources to pay not only for emissions that exceed their emission allocation levels but also for the right to emit *below* those levels. There is no legal basis for charging sources for the right to emit tons of emissions that are *within* their allowance allocation levels -- indeed, the very word "allowance" denotes that a source is allowed to emit within the limits of its allowance allocations -- and providing revenue to the U.S. Treasury is not a legitimate purpose of section 110(a)(2)(D)(i)(I). Moreover, EPA has not shown that any legal authority exists for EPA to auction allowances and thereby impose what amounts to a tax, with tax revenue flowing to the federal government.

III. The Proposed Transport Rule Should Not Include an Initial Compliance Deadline of 2012.

Many of the flaws in the Proposed Transport Rule, described in the sections that follow, could be resolved or at least somewhat ameliorated by deferring the initial 2012 compliance date and having CAIR's allowance trading and enforcement mechanisms remain in effect pending implementation of the Transport Rule. It is unreasonable and unrealistic, for example, to expect emission reductions required by the proposal to be achieved by January 1, 2012, barely six months after the date on which EPA expects to issue a final Transport Rule.

A. An Initial Compliance Deadline of 2012 Will Not Allow Enough Time for Sources To Make the Changes Necessary To Comply with the Transport Rule, or for States To Develop Implementation Plans.

An initial compliance deadline of January 1, 2012, will not allow sufficient time for sources to make the adjustments necessary to comply with the rule. For example, a compliance deadline of 2012, following a mid-2011 date for final promulgation of the rule,[9] would not allow enough time for sources to install low NOx burners ("LNBs"), and in many cases, would not allow sufficient time for sources to switch to burning lower sulfur coal. *See* section V *infra.* Additionally, much of the modeling that EPA used to develop the proposed rule is flawed, due to the approach that EPA adopted, as well as many of the assumptions EPA made with respect to issues such as the emission controls that will be installed on, and retirement of, specific units by 2012. EPA must resolve and correct these problems, and either withdraw the proposed rule and reinitiate rulemaking with a new proposal or issue a supplemental notice of proposed rulemaking for public comment. Under these circumstances, rulemaking could not be completed before the beginning of 2012.

The tight implementation schedule that EPA proposes is in effect made even tighter by the fact that EPA is already changing the terms of the proposed rule. As discussed above, on September 1, 2010, midway through the public comment period on the proposed rule, EPA published its NODA, announcing information that in effect will result in substantial changes to the proposed rule and noting that further changes are to come. Among other things, the NODA

[9] As discussed in these comments, the NODA belies any argument that sources (or states) could possibly rely on the proposed rule's budgets and allowance allocations to develop SIPs or, much less, source compliance plans.

announced the release of (i) an updated version of the National Electric Energy Data System ("NEEDS"), which provides the unit-level EGU characteristics used as inputs for the Integrated Planning Model ("IPM"), (ii) results of new base case and policy case modeling runs using an updated version of IPM, and (iii) results of new base case and policy case modeling runs using an updated version of IPM and including data from the Energy Information Administration's Annual Energy Outlook 2010 natural gas resource assumptions. 75 Fed. Reg. at 53614/2-3. It also announces the release of "[a] summary of other planned input updates to be implemented in the final rulemaking." 75 Fed. Reg. at 53614/3. The data released in connection with the NODA will, when applied by EPA, change substantially the statewide budgets and allowance allocations for 2012 and the allowance allocations for 2014,[10] and there will presumably be additional changes leading up to promulgation of a final rule based on the planned input updates that EPA says will be implemented later.

The scope of the impact that the new data will have is clear at a glance. For example, the parsed file that EPA released in connection with the proposed rule, showing the initial IPM run, indicates that IPM projected about 23,723 MW of new coal generation from unidentified plants yet to be built in 10 different states. *See* IPM Run File "TR SB Limited Trading", *available at* http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html.[11] By contrast, the updated parsed file that EPA added to the docket in connection with the NODA appears to indicate that IPM projected only about 2,001 MW of new coal generation from unidentified plants yet to be

[10] EPA did not update the state budgets for 2014. *See* 75 Fed. Reg. at 53614/3 ("The [state-level emissions] caps have not been modified to account for any changes that the new modeling might suggest").

[11] This spreadsheet is listed in the docket at Document No. EPA-HQ-OAR-2009-0491-0092, but that document number is linked to a summary report, and not the full spreadsheet. *See* http://www.regulations.gov/search/Regs/home.html#docketDetail?R=EPA-HQ-OAR-2009-0491.

built in *four* states. *See* Docket ID No. EPA-HQ-OAR-2009-0491-0312, IPM Run - TR SB Limited Trading v.4.10 - 2014 Parsed File (Sept. 1, 2010), *available at* http://www.regulations.gov/search/Regs/home.html#docketDetail?R=EPA-HQ-OAR-2009-0491. This is likely to be merely one indicator of the substantial changes in EPA's proposal that will result from use of the NODA information, and the impact of the future changes that EPA anticipates remains to be seen. Clearly, there is no way for sources to begin planning for compliance based on the information that EPA has provided in the docket.

In addition, EPA states in the proposed rule that it intends to propose additional interstate transport determinations in the future as EPA revises the NAAQS for $PM_{2.5}$ and ozone, and that these proposals "could require greater emissions reductions from states covered by [the Proposed Transport Rule] and/or require reductions from states not covered" by the current proposal. 75 Fed. Reg. at 45213/3. It would be very difficult for states and electric generating companies to plan for compliance with a rule under which the standards of compliance change along with the frequent changes to the ambient standards. EPA should keep state budgets (and allowance allocations, to the extent EPA sets allowance allocations) as constant as possible, revising them only when essential and in a way that provides ample time for compliance, rather than changing them sporadically each time EPA revises a NAAQS.

Finally, the proposed rule -- and especially its 2012 first-phase compliance date -- is fundamentally inconsistent with the CAA because it effectively deprives states of the time they need to develop, submit, and receive EPA approval of SIPs before the program begins. *See* section IV *infra*.

B. A Compliance Deadline in 2012 Is Neither Necessary Nor Appropriate.

In any event, EPA has provided no reasonable justification for its proposal to require a compliance date as early as 2012. To begin with, according to statements by EPA representatives, the emission levels required in the 2012 phase for the most part reflect the emission reductions that would occur even in the absence of the Transport Rule. However, as noted above, in a number of cases, EPA has made incorrect assumptions regarding emission reductions that, in the absence of this new rule, would occur at units by 2012. *See* section VIII.A *infra*.

Additionally, notwithstanding these assertions that the emission reductions required in 2012 would occur even without the Proposed Transport Rule, EPA indicated in a presentation given in July 2010, when it announced the proposed rule, that it projects that the proposed rule would reduce SO_2 emissions by an additional one million tons per year ("TPY") in 2012 beyond what CAIR would have accomplished: from an emission level of 5.1 million TPY under CAIR to 4.1 million TPY under the proposed rule.[12] In fact, during a meeting held shortly after EPA issued the proposed rule but before its publication in the Federal Register, EPA acknowledged that, according to the Agency's projections, the 2012 state budgets in the Proposed Transport Rule would reduce SO_2 emissions by 1.2 million TPY, from 5.1 million TPY under CAIR to 3.9 million TPY under the Proposed Transport Rule. EPA failed to explain this apparently substantial discrepancy or how over a million *additional* tons of emissions would be eliminated in a phase of the program that is intended merely to replicate what would have occurred anyway.

Moreover, EPA has not shown that emission reductions beyond those required by CAIR are necessary. EPA's own data show that existing controls are working to reduce emissions; the result is that concentrations of SO_2 and NOx in the ambient air have declined steadily in recent

[12] *See* Table V-1 at section V *infra*, based on a table included in EPA's "Overview Presentation 7/26/10," at slide 33, *available at* http://www.epa.gov/airquality/transport/actions.html and reproduced at 75 Fed. Reg. at 45217 (Table III.A-4).

years.[13] The D.C. Circuit's opinion in *North Carolina v. EPA* did not require, or even remotely suggest, that the overall degree of emission reductions required under CAIR was less than that necessary to comply with CAA section 110(a)(2)(D)(i)(I). Nor did the court include in its opinion any mandate that the replacement rule for CAIR must include a compliance date in 2012 or within any period of time as short as six months after final rule promulgation.[14]

[13] EPA's most recent Status and Trends Report indicates that nationwide concentrations of nitrogen dioxide (NO_2) decreased by 27 percent between 2001 and 2008 and by 35 percent between 1990 and 2008, and that nationwide concentrations of SO_2 decreased by 30 percent between 2001 and 2008 and by 59 percent between 1990 and 2008. EPA, "Our Nation's Air Status and Trends Through 2008," 1, 31 (Feb. 2010) ("EPA's Trends Report"), *available at* http://www.epa.gov/airtrends/2010/index.html. Additionally, according to EPA, nationwide 8-hour concentrations of ozone decreased by 10 percent between 2001 and 2008 and by 14 percent between 1990 and 2008, and nationwide annual and 24-hour concentrations of $PM_{2.5}$ decreased by 17 and 19 percent, respectively, between 2001 and 2008. *Id.* at 1, 15, 20.

[14] The D.C. Circuit's finding that the 2015 compliance deadline for the second phase of CAIR was unlawful because "EPA did not make any effort to harmonize CAIR's Phase Two deadline for upwind contributors to eliminate their significant contribution with the attainment deadlines for downwind areas," 531 F.3d at 912, does not mandate a 2012 compliance deadline. In the preamble to the proposed rule, EPA attempts to justify its proposed 2012 compliance deadline in part by asserting that it is coordinated with the attainment deadline for the 8-hour ozone NAAQS. In doing so, EPA focuses on the June 2013 maximum deadline for areas classified as "serious" nonattainment for 8-hour ozone, but acknowledges that "[areas] that have not yet attained the [8-hour ozone] standard have maximum attainment dates ranging from 2010 . . . to 2018." 75 Fed. Reg. at 45301/1. EPA also relies heavily on the statement in CAA section 172(a)(2)(A) that the attainment date for nonattainment areas "shall be the date by which attainment can be achieved as expeditiously as practicable" to justify the proposed 2012 and 2014 compliance deadlines. *See, e.g., id.* at 45300/2 ("EPA chose these dates to coordinate with the NAAQS attainment deadlines and to assure that reductions are made as expeditiously as practicable"); *id.* at 45300/3 ("EPA believes that [the 2014] deadline is as expeditious as practicable for the installation of the controls needed for compliance"); *id.* at 45301/2 (in addition to being coordinated with the 2013 maximum attainment deadline for serious ozone nonattainment areas, the 2012 deadline "is also consistent with the requirement that states attain the NAAQS as expeditiously as practicable"). This requirement, that attainment be achieved as expeditiously as practicable, must be read in the context of the remainder of the Act. It does not give EPA the authority to impose a FIP before allowing states the opportunity to develop and submit SIPs. Neither the CAA nor the court's opinion in *North Carolina v. EPA* requires EPA to accelerate the PTR's compliance dates to the extent proposed.

EPA should not adopt the 2012 compliance deadline in the Proposed Transport Rule and should not in any event consider any compliance date earlier than 2015.[15] In any event, if EPA promulgates a Transport Rule that, like the proposed rule, includes requirements more stringent than CAIR, the compliance deadline must reflect the degree of stringency of those requirements.

UARG is not alone in its concern regarding the initial compliance date. Last year, for example, the Lake Michigan Air Directors Consortium ("LADCO") strongly recommended that any CAIR replacement rule include an initial compliance date no earlier than 2017 for any significant additional emission reduction requirements. *See* Letter from LADCO to Administrator Jackson (Sept. 10, 2009) ("LADCO Letter") at 1. LADCO explained in its recommendations to EPA that it had conducted a state-by-state analysis that indicated that installation of significant new NOx and SO_2 controls -- specifically, installation of selective catalytic reduction systems ("SCRs") and flue gas desulfurization systems ("FGDs" or "scrubbers") -- would not be possible in LADCO states before 2017. *Id.* at 1, attachment at 4-5.[16]

Moreover, EPA ignores the fact that many electric generating companies are not in a position to undertake fuel switching in the near term because of binding fuel contracts. Many electric generating companies may also face capital-access or other constraints that would prevent them from undertaking emission control projects, except perhaps at prohibitively high

[15] Nothing in these comments should be construed as suggesting that a compliance date as early as 2015 is necessarily appropriate or could be justified.

[16] According to LADCO, a fundamental assumption for this state-by-state analysis was a July 2012 start date for the planning, engineering, and construction of any new NOx or SO_2 controls, reflecting a January 2011 promulgation date for the final Transport Rule and another 18 months for adoption of SIPs. *See id.* at 1, attachment at 4. Thus, LADCO properly recognized that a substantial amount of time would be necessary after promulgation of EPA's final rule for states to develop SIPs and submit them to EPA for approval.

interest rates, in the near term. In addition, electric generating companies have fiduciary obligations that prevent them from making commitments to capital projects while the nature and scope of emission reductions remain uncertain. As described above in section III.A, the scope of emission reductions that will ultimately be required under the Transport Rule is far from certain.

Despite EPA's suggestions to the contrary, promulgation of compliance dates later than those that EPA proposes would not result in increased emissions. CAIR could remain in place and would continue to maintain a strong and effective program of emission reductions pending the initial compliance deadline for the Transport Rule. In fact, electric generating companies will continue to have an obligation to achieve CAIR emission reduction requirements, including the phase II requirements, pending implementation of the Transport Rule.

UARG further notes that it would be possible for EPA to encourage early emission reductions beginning in 2012 under the proposed rule even if the initial binding compliance date under the rule was not until some years later. One possible approach would be to set "shadow" allowance allocations, using the best data available, for 2012 and each subsequent year until the new program begins. Then, during the period leading up to the new program's initial compliance year, EPA (or, more properly, a state) could credit sources with additional allowances corresponding to the number of tons they emitted *below* their shadow allowance allocation levels in those years, with those allowances eligible to be banked and used beginning in the first compliance year. The ability to earn allowances -- usable once the new program begins -- for early reductions would give sources a meaningful incentive to reduce their emissions prior to the start of the program, while allowing them the time they need to make the adjustments necessary for compliance, and affording states sufficient time to develop and submit SIPs consistent with the Act.

In sum, the fact that EPA's proposal to set an initial compliance deadline of January 1, 2012, is so fraught with difficulty and uncertainty is a stark illustration of the ill-advised nature of this attempt to force implementation of such a complex and demanding rule in only six months. EPA should take the time necessary to correct the many errors in the proposed rule, as described in these comments, and allow adequate time for states to develop SIPs and for sources to make the adjustments necessary to comply with the rule, rather than rushing to implementation as it proposes to do.

IV. The Proposed Transport Rule Would Unlawfully Supplant the Role of States Under the Act.

A. EPA Has No Authority To Promulgate a FIP To Replace CAIR.

EPA unabashedly proposes the Transport Rule as a FIP rule. Indeed, promulgation and implementation of the Transport Rule pursuant to the schedule that EPA proposes would make it nearly impossible for states to develop, submit, and receive EPA approval of SIPs in time to use them for implementation of the first phase of the program. EPA's assertion that promulgation of FIPs "would in no way affect the right of states to submit . . . a SIP that replaces the federal requirements of the FIP with state requirements," 75 Fed. Reg. at 45342/2, misses the point. The opportunity to replace federal requirements with a state plan at some point in the future does not satisfy the requirement that EPA allow the opportunity for states to develop their own plans, at the outset of the program, to comply with the Transport Rule. EPA's proposal would effectively bypass the states, at least with respect to the first phase of the program. This is unsupported by anything in the proposed rule and is contrary to the Act.

The CAA contemplates that states must be given a meaningful opportunity to develop SIPs and to submit them to EPA for review and approval before implementation of a new or revised NAAQS. CAA § 110(a)(1). *See also* CAA § 101(a)(3) ("air pollution control at its source is the primary responsibility of States and local governments"); CAA § 107(a) ("Each State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State by submitting an implementation plan for such State which will specify the manner in which national primary and secondary ambient air quality standards will be achieved and maintained within each air quality control region in such State"). The CAA provides that EPA may promulgate a FIP within two years *after* the Administrator (i) finds that a state has failed to submit a SIP or has submitted a SIP that does not satisfy the minimum criteria set forth in section 110 of the Act, or (ii) disapproves a SIP in whole or in part, unless the state has corrected the deficiency and the Administrator has approved the SIP. CAA § 110(c)(1). With respect to interstate air pollution, section 110(a)(2) provides that each state shall, in the first instance, submit a SIP to EPA that "contain[s] adequate provisions" prohibiting the emissions proscribed by section 110(a)(2)(D)(i). And section 110(k)(5) of the Act states that:

> Whenever the Administrator finds that the [SIP] for any area is substantially inadequate to attain or maintain the relevant [NAAQS], *to mitigate adequately the interstate pollutant transport* described in [section 176A or section 184 of the Act], or to otherwise comply with any requirement of [the Act], the Administrator shall require the State to revise the plan as necessary to correct such inadequacies. The Administrator shall notify the State of the inadequacies, and may establish reasonable deadlines . . . for the submission of such plan revisions.

CAA § 110(k)(5) (emphasis added).

Although EPA undoubtedly has a role in implementation of NAAQS, including interstate transport requirements, that role is plainly "secondary." *Train v. Natural Res. Def. Council*, 421 U.S. 60, 79 (1975). The D.C. Circuit has interpreted the "partnership between EPA and the states for the attainment and maintenance of national air quality goals," as set forth in the Act, as follows: "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."

Natural Res. Def. Council v. Browner, 57 F.3d 1122, 1123 (D.C. Cir. 1995). The court noted further that the Act's SIP provisions give states "authority to make the many sensitive technical and political choices that a pollution control regime demands." *Id.* at 1124. Here, the authority of states to develop SIPs and submit them to EPA for approval would allow the states to determine, based on state-specific concerns and the specialized knowledge of state officials, how best to achieve the emission reductions that may be necessary to satisfy section 110(a)(2)(D) by allocating allowances to sources within the state. EPA lacks the knowledge of state-specific conditions that state agencies can bring to bear in developing implementation plans. For example, within a state, various agencies and regulatory bodies may have input to the process for setting policy for allocating allowances, to assure not only environmental protection but also effective energy policies and electric reliability.

EPA may issue a FIP, "rescind[ing] state authority," *id.*, only *after* a state fails to develop and submit a complete SIP and receive Agency approval of it. CAA § 110(c)(1). The Act grants no authority to EPA to promulgate a FIP without first giving the states adequate time and a real opportunity to develop and submit SIPs that reflect each state's "sensitive . . . choices" on how to implement section 110 (a)(2)(D)(i)(I). 57 F.3d at 1124. In other words, EPA has no "roving commission" to leapfrog over the SIP process and impose its own choices on states and regulated parties. *Michigan v. EPA*, 268 F.3d 1075, 1084 (D.C. Cir. 2001).

As noted above, it is a bedrock principle that, under the CAA, EPA's role is a decidedly "secondary" one -- one that requires the Agency to give states room and time to act:

> [EPA] is relegated by the Act to a secondary role in the process of determining and enforcing the specific, source-by-source emission limitations which are necessary if the national standards it has set are to be met. Under [CAA] § 110(a)(2), the Agency is required to approve a state plan which provides for the timely attainment and subsequent maintenance of ambient air standards, *and which also satisfies that section's other*

> *general requirements*. The Act gives the Agency no authority to question the wisdom of a State's choices of emission limitations if they are part of a plan which satisfies the standards of § 110(a)(2), and the Agency may devise and promulgate a specific plan of its own *only* if a State fails to submit an implementation plan which satisfies those standards. § 110(c). Thus, so long as the ultimate effect of a State's choice of emission limitations is compliance with the national standards for ambient air, the State is at liberty to adopt whatever mix of emission limitations it deems best suited to its particular situation.

Train, 421 U.S. at 79 (emphases added) (footnote omitted); *see id.* at n.16 (listing exceptions to this principle, where specific CAA provisions authorize EPA to determine emission limitations; none of those provisions apply here). Indeed, the D.C. Circuit and other courts of appeals have recognized repeatedly and consistently the well-established relationship between the federal government and the states with respect to interstate pollution regulation -- and the limited scope of federal authority. As the D.C. Circuit explained,

> EPA determines the ends--the standards of air quality--but Congress has given the states the initiative and a broad responsibility regarding [the] means to achieve those ends through state implementation plans and timetables of compliance . . . . The Clean Air Act is an experiment in federalism, and the EPA may not run roughshod over the procedural prerogatives that the Act has reserved to the states.

Virginia v. EPA, 108 F.3d 1397, 1408 (D.C. Cir. 1997) (quoting *Bethlehem Steel Corp. v. Gorsuch*, 742 F.2d 1028, 1037-38 (7th Cir. 1984));[17] *see also Michigan v. EPA*, 213 F.3d 663, 687 (D.C. Cir. 2000) (noting that the validity of the statewide emission budget program that was the central feature of EPA's NOx SIP Call rule depended on "whether the program constitutes an impermissible source-specific means rather than a permissible end goal"; the court affirmed that rule because it "merely provide[d] the levels to be achieved by *state-determined* compliance

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[17] In *Virginia*, the D.C. Circuit held unlawful an EPA rule designed to reduce regional ozone pollution in the northeastern United States because it required the affected states to adopt either California's vehicle emission program or a more stringent program. The court held that EPA had exceeded its authority under section 110 by mandating the means of compliance with the Act, which is a decision committed to the states. 108 F.3d at 1414-15.

mechanisms" and allowed states "real choice with regard to the control measure options available to them to meet the budget requirements" (emphasis added)). The principle that it is the right and responsibility of the states to develop plans to implement the Act's requirements could not be more clear.[18]

The Proposed Transport Rule makes equally clear, however, that EPA's proposal would violate this principle. The proposal's preamble articulates the view that EPA has broad responsibility to determine exactly what states, and sources in the states, must do to comply with section 110(a)(2)(D)(i)(I). EPA explains that its proposal "identifies emission reduction responsibilities of upwind states, and also proposes enforceable FIPs to achieve the required emissions reductions in each state through cost-effective and flexible requirements for power plants," and that "[e]ach state will have the option of replacing the [FIP with a SIP] to achieve the required amount of emissions reductions from sources selected by the state." 75 Fed. Reg. at 45212/3. In other words, under EPA's new approach, the states and their sources would be required to comply with the FIP unless and until -- after the prolonged period needed for SIP development -- SIPs are in fact developed, submitted, and approved by EPA (if and when EPA decides to approve them). This scheme is plainly contrary to the terms of the Act and the states-first principle recognized and enforced by the courts. EPA's passing reference to states' right to "replace[] the federal requirements of the FIP with state requirements," 75 Fed. Reg. at 45342/2, is *not* an acknowledgement of the right granted to states in section 110 of the Act. Congress gave the states the right to develop and submit SIPs implementing the Act's requirements *in the*

[18] EPA acknowledged this principle in its final action on its NOx SIP Call rule. *See* 63 Fed. Reg. at 57369/1-2 ("Relying on *Train v. NRDC* . . ., the [D.C. Circuit in] *Virginia* . . . found that under title I of the CAA, EPA is required to establish the overall air quality standards, but the States are primarily responsible for determining the mix of control measures needed to meet those standards and the sources that must implement controls, as well as the applicable level of control for those sources").

first instance, based on state-specific considerations. No amount of expediency can justify violation of the terms of the Act and upsetting the balance that Congress struck between federal and state government. As the Supreme Court noted decades ago, "the Agency may devise and promulgate a specific plan of its own *only if* a State fails to submit an implementation plan which satisfies [the standards of § 110(a)(2)]." *Train*, 421 U.S. at 79 (emphasis added).

EPA claims that its findings regarding the pre-CAIR SIPs, *see* 75 Fed. Reg. at 45341/3-45342/2, justify the Agency's proposal to supplant the role of the states under the Act. EPA's error is perhaps most starkly revealed by this attempt to assign blame to the states for faithfully implementing the underlying section 110(a)(2)(D)(i)(I) rule -- CAIR -- that EPA itself promulgated to guide the states' implementation of that CAA provision. In CAIR, EPA took it upon itself, much as it had done in the NOx SIP Call rule, to set broad parameters -- in the form of statewide emission budgets -- for the states' implementation of their section 110(a)(2)(D)(i)(I) obligations. That *EPA* rule was later held unlawful through no fault of the states that worked to implement it. Thus, EPA's justification in the proposed rule for not allowing states sufficient time to develop new SIPs, and to submit them to EPA for review and approval, before implementation of the program begins is contrary to the Act as construed by the Supreme Court and the D.C. Circuit.

In particular, EPA's position that its 2005 findings that CAIR states had failed to submit SIPs satisfying their section 110(a)(2)(D)(i)(I) obligations for the 1997 $PM_{2.5}$ and ozone NAAQS provide a legal basis for the Proposed Transport Rule FIPs, *see* 75 Fed. Reg. at 45341/3 –

45342/1, is without merit.[19] EPA attempts to justify this conclusion by explaining that, under CAIR:

> EPA concluded that the states in the CAIR region would meet their section 110(a)(2)(D)(i) obligations . . . by complying with the CAIR requirements. Consequently, states within the CAIR region did not need to submit a separate SIP revision to satisfy the section 110(a)(2)(D)(i) requirements provided they submitted a SIP revision to satisfy CAIR . . . . [T]he Court granted several petitions for the review of . . . CAIR and found . . . that EPA had not demonstrated that . . . CAIR effectuates the statutory mandate of section 110(a)(2)(D)(i)(I). The EPA approvals of the CAIR SIPs preceded the remand of . . . CAIR . . . . Therefore, because the D.C. Circuit found CAIR and the CAIR FIPs unlawful, EPA's approval of the provisions of a state's SIP submittal as addressing the requirements of . . . CAIR could not satisfy the state's section 110(a)(2)(D)(i)(I) obligation.

75 Fed. Reg. at 45341/3. This explanation -- that the states are in default of their SIP obligations because the D.C. Circuit held that EPA's promulgation of CAIR was unlawful -- is nonsensical. The states had no choice but to comply with CAIR or else to default on their EPA-determined SIP obligation. States cannot be penalized, or lose their right under the CAA to decide how to implement a CAIR replacement rule, because they complied with an EPA rule that, as later determined by the D.C. Circuit, violated the Act.

The D.C. Circuit has held that, where states have been prevented from meeting their statutory obligations due to the failure of EPA to comply with applicable CAA provisions, the deadline clock for states to submit SIPs should be restarted. *See, e.g., Natural Res. Def. Council v. EPA*, 22 F.3d 1125, 1137 (D.C. Cir. 1994) ("we think it would be unfair to penalize states that reasonably relied on and complied with the EPA's [regulatory decision] . . . . [W]e direct that the sanction clock for . . . SIPs start, if necessary, from the time of SIP disapproval in accordance

[19] Some states may have already satisfied any obligation that they have under section 110(a)(2)(D)(i)(I) for these NAAQS and the 2006 $PM_{2.5}$ NAAQS. If a state were to have already implemented, under state law, the emission reductions necessary to satisfy the requirements of the Transport Rule, there would not even arguably be any basis for EPA to impose a FIP on that state.

with the statutory scheme"); *see also Natural Res. Def. Council v. Thomas*, 805 F.2d 410, 435 (D.C. Cir. 1986) (holding that EPA was required to extend the deadline for compliance with automobile NOx emissions standards when EPA was a year late in promulgating the standards, and explaining that, "[a]lthough fully cognizant of the frustration the drafters would have felt, could they have foreseen the course of events, we nonetheless find that they enacted a four year leadtime requirement and we have no alternative but to enforce it, unless or until Congress decrees otherwise"). Thus, the three-year deadline for CAA section 110(a)(2)(D)(i)(I) interstate transport SIP submissions for the 1997 NAAQS should be restarted due to EPA's unlawful adoption of CAIR, and should begin to run upon EPA's promulgation of a valid final rule replacing CAIR.

Likewise, EPA's explanation that, with respect to the 2006 24-hour $PM_{2.5}$ NAAQS, it will finalize FIPs for states that have not submitted SIPs and those for which EPA finds the previously-submitted SIPs to be incomplete or inadequate, 75 Fed. Reg. at 45342/2,[20] lacks merit and is contradicted by EPA's own underlying justification for proposing the Transport Rule. In the proposed rule (as in CAIR), EPA plainly takes the position that it has the authority, if not the obligation, to set the overall terms for states' implementation of section 110(a)(2)(D)(i)(I) with respect to any new or revised NAAQS. Given this circumstance, therefore, the affected states' section 110(a)(2)(D)(i)(I) obligation with respect to the 2006 24-hour $PM_{2.5}$ NAAQS should be deemed to begin to run only upon EPA's promulgation of a valid final rule setting guidelines (in the form of statewide emission budgets) for the states (*e.g.*, a final CAIR replacement rule that is consistent with the CAA).

[20] *See* 75 Fed. Reg. 32673 (June 9, 2010) (finding that certain states had failed to submit SIPs satisfying CAA § 110(a)(2)(D)(i)(I) with respect to the 2006 24-hour $PM_{2.5}$ NAAQS).

B. EPA Lacks Authority To Impose Any Unit-Specific Emission Rate Limits -- Such as the Limits in the Direct Control Remedy Option -- Under Section 110(a)(2)(D)(i)(I).

With respect to EPA's Direct Control Remedy Option, the second alternative option on which EPA requests comment in the Proposed Transport Rule, EPA explains that it would regulate individual units directly by assigning emission rate limits to individual units. 75 Fed. Reg. at 45330/1. As discussed above, EPA is without authority to dictate how a state implements section 110(a)(2)(D)(i)(I). As LADCO aptly observed in 2009 in its recommendations to EPA, "unit-specific performance standards go beyond the requirements of section 110 [of the Act] and the scope of the CAIR replacement rule." LADCO Letter, attachment at 5. Indeed, all such matters are reserved to the states in the first instance. *See, e.g., Michigan*, 213 F.3d at 686 ("section 110 left to the states 'the power to [initially] determine *which sources* would be burdened by regulation and to *what extent*.'") (quoting *Union Elec. Co. v. EPA*, 427 U.S. 246, 269 (1976)) (alteration and emphases in original); *Virginia*, 108 F.3d at 1408 (same). Consistent with those cases, EPA at most can determine what overall emission tonnage level a state must achieve; it may not impose any unit-specific rules or requirements.

V. The January 2012 and January 2014 Compliance Deadlines Set Forth in the Proposed Transport Rule Are Unreasonable and Unrealistic.

In materials prepared to explain its Proposed Transport Rule,[21] EPA made the following assumptions about how low SO_2 and NOx emission levels from EGUs would be as a result of (a) the implementation of CAIR and other on-the-books regulations, and (b) the implementation of the Proposed Transport Rule:

[21] This table is based on a table included in EPA's "Overview Presentation 7/26/10," at slide 33, *available at* http://www.epa.gov/airquality/transport/actions.html. A table with the same emission numbers appears at 75 Fed. Reg. at 45217 (Table III.A-4).

Table V-1						
		2005	**2012**		**2014**	
		Actual	**CAIR**	**Transport Rule**	**CAIR**	**Transport Rule**
SO_2 (Million Tons)		9.5	5.1	4.1	4.6	3.3
NOx (Million Tons)	**Annual**	2.9	1.7	1.6	1.7	1.6
	Ozone Season	1.0	0.8	0.7	0.8	0.7

Table V-1 demonstrates that EPA expects its PTR to require substantial additional EGU emission reductions beyond those that have been (or would be) achieved through implementation of CAIR. Despite how much EPA expects its PTR to accomplish in terms of achieving additional emission reductions, however, EPA proposes to give affected sources very little time to achieve those additional reductions.

Specifically, EPA assumes that affected EGUs will be able to reduce their SO_2 emissions from 5.1 million tons per year to 4.1 million tons per year between mid-2011 (when EPA expects to take final action on the PTR[22]) and January 1, 2012. This reduction, says EPA, can be

[22] In presenting the schedule that affected source owners would face in making the additional emission reductions that the final Transport Rule will impose, EPA implies throughout the PTR preamble that the appropriate time for source owners to initiate work on any emission controls that are needed to meet the rule's requirements is when the Transport Rule is finalized. For example, at 75 Fed. Reg. at 45273/1, EPA makes "mid-2011 (when the Agency anticipates finalizing this rule)" the start of the time period in which source owners are to design and construct additional FGD and SCR systems at their plants. EPA is correct in taking this approach. It would be entirely inappropriate for EPA either to require affected source owners to initiate serious work on additional control systems, or to assume that source owners will voluntarily start such efforts, before the Transport Rule is final. Indeed, it would be imprudent for regulated sources, and inconsistent with fiduciary obligations for any affected electric generator, to start making in the near term any major investments in the design and construction of controls that may or may not be needed depending on the terms of the final Transport Rule and the terms of other emission control rules that are scheduled to be published by EPA in the near future and that could affect the control options faced by power plant owners. This is particularly so given the uncertainty as to the outcome of the present rulemaking that EPA has

accomplished if affected companies (a) just complete the installations of FGD units that are already underway, and (b) supplement the emission reductions from those controls by switching some of their units to burning lower sulfur fuels. *See* 75 Fed. Reg. at 45273/2. Then, relying in large part on information from a March 2005 study,[23] EPA takes pieces of information from retrofit experiences at two power stations and uses those scant data to conclude that it is possible for owners of EGUs to reduce their emissions even further (down to 3.3 million tons annually) by January 1, 2014, through the installation of additional FGD units, which -- EPA claims -- can be designed, permitted, and constructed in just 27 months. *Id.* at 45273/1.

Similarly, EPA assumes power plant owners will be able to reduce their EGUs' annual and seasonal NOx emissions by substantial amounts by January 1, 2012, by completing already-in-the-pipeline projects to install SCR reactors and by constructing more LNB systems that -- according to EPA -- can be installed in the few months between the time that the PTR is scheduled to be finalized in mid-2011 and January 1, 2012. And if any additional NOx reductions are needed (although EPA's projections as summarized in Table V-1 above suggest that no such additional NOx reductions will be needed), then affected electric generating companies can install additional SCR units by January 1, 2014, because -- according to EPA (again relying on its 2005 Report) -- it takes only "approximately 21 months" to design, permit, and construct SCR units. *Id.* at 45273/1.

As discussed in greater detail in other portions of these comments and in the comments being filed by individual UARG members, EPA has substantially *over*estimated the number of

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created by publishing the NODA and indicating that the emission budgets and allowance allocations in the final Transport Rule could be very different from those that EPA has proposed.

[23] EPA, "Boilermaker Labor Analysis and Installation Timing" (March 2005), *available at* www.epa.gov/interstateairquality/pdfs/finaltech05.pdf (hereinafter "2005 EPA Report" or "2005 Report").

FGD and SCR installations that are now under construction and can be operational by January 1, 2012. Therefore, the Agency has greatly *under*estimated the number of FGD and SCR installations that affected utilities would have to undertake and complete between January 1. 2012, and January 1, 2014, to meet the PTR's requirements. Even worse than this, though, EPA has vastly underestimated the amount of time that it takes utilities to design, permit, construct, and start up new FGD and SCR units. It will take longer than 30 months -- in some cases significantly longer than 30 months -- for companies to retrofit FGD and SCR units at existing EGUs. For all of these reasons, it will not be possible for affected EGUs to achieve the substantial SO_2 and NOx emission reductions that -- under the terms of the PTR -- must be achieved by that rule's January 2012 and January 2014 deadlines.

In light of this, EPA should decide not to call for the steep additional emission reductions demanded by the PTR because, as discussed elsewhere in these comments, such additional reductions are *not* needed to reduce significant regional contributions to downwind nonattainment and interference with maintenance. In the alternative, EPA should extend the PTR's emission reduction deadlines by at least a two-year period beyond the proposed 2014 compliance date (plus an additional interval of time that reflects (i) any additional time that EPA takes to complete this rulemaking beyond mid-2011 and (ii) the reasonable period of time needed by states to implement emission budgets through SIP revisions after final promulgation of EPA's rule). The following subsections of this part of UARG's comments provide more detailed information on the unreasonableness of the emission reduction requirements that EPA has proposed. Section V.A provides an overview of the many steps that power plant owners must follow in order to retrofit their power plants with control equipment like FGD and SCR units. A more detailed discussion of these steps is provided in a separate report, which is attached hereto as Attachment I, and is incorporated by reference herein: Cichanowicz, J.E., "Implementation Schedules for Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Process Equipment" (Oct. 1, 2010) (hereinafter "Implementation Schedules Report"). The Implementation Schedules Report was prepared by J. Edward Cichanowicz, who has been involved in -- and has first-hand knowledge of the challenges that can be posed by -- the design, permitting, and construction of FGD and SCR retrofits at many power plants throughout the United States. Next, section V.B of these comments directly addresses the few examples and arguments that EPA has made in support of its highly abbreviated compliance deadlines. Then sections V.C and V.D of these comments provide a broad range of more current examples of FGD and SCR retrofits, respectively. These examples demonstrate the complexity and time-consuming nature of the retrofit installation processes at most sites. EPA's failure to understand this has led the Agency to systematically underestimate the length of time it now takes to retrofit FGD and SCR systems at power plants.

A. Background.

EPA places all FGD and SCR installation activities into one of essentially three broad overlapping categories: (1) conducting an engineering review of the facility and awarding a procurement contract; (2) obtaining a construction permit; and (3) installing the control technology. EPA, "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipoint Strategies" (2002) at 7-8, 20, *available at* www.epa.gov/clearskies/pdfs/multi102902.pdf (hereinafter "2002 EPA Report").[24] Categorizing the numerous activities involved in installing FGD and SCR systems in such a general way,

[24] The 2002 EPA Report also notes that source owners must obtain an operating permit for new control equipment but does not suggest that the process of applying for and obtaining such a permit will add months to the overall process of getting SCR and FGD equipment ready to operate. This step can in fact add many months to the timeline for pollution control retrofits.

however, tends to mask the overall complexity of the numerous steps that electric generating companies must actually follow in order to design, permit, and construct FGD and SCR systems at their power stations.

The following is a more detailed discussion of all the steps that power plant owners typically take when they retrofit FGD and SCR systems at their stations.

1. Step One Requires More Than Conducting an Engineering Review.

EPA makes the first step of the process seem simple and straightforward: conduct an engineering review. And EPA then claims that step can be completed in no more than four months. In fact, as explained in the Implementation Schedules Report and in the comments of individual UARG members, EPA's "first step" is actually quite a few steps, including (1) doing design work extensive enough to allow the preparation of detailed specifications concerning the actual control equipment to be installed, the equipment's control efficiency, potential byproduct species, and project capital and operating costs; (2) identifying qualified control equipment vendors and qualified contractors for project construction; (3) soliciting and reviewing bids and then selecting vendors and contractors; and (4) negotiating contract terms and issuing the requisite contracts.

There is no basis for EPA's suggestion that all these activities can be completed in four months or less even at sites with few complications or in situations where companies are able to develop system-wide designs for parts of the installations.[25] The Implementation Schedules Report cites many reasons why this part of the process takes much longer than four months, including (but not limited to) the existence of unusual spatial limitations or related challenges at

[25] The Implementation Schedules Report (in section 2.2.1) describes how several companies have used system engineering approaches to reduce their engineering timelines to a year or just under a year -- still far longer than EPA's suggested four-month schedule. And not all plant owners can use system-wide engineering approaches in any event. *Id.*

a particular site (*e.g.*, little room to maneuver during construction activities or physical features at the site that require more-extensive-than-normal activities to secure a place to put physically large structures like the SO_2 absorber towers that are part of FGD systems); the possibility that a source owner could use new fuel sources (particularly for FGD installations, which may make possible the burning of coals with higher sulfur content than have historically been used at a station); and the existence of other unusual site conditions -- such as soil characteristics, the presence of underground utilities, and available water -- that will influence the selection of the precise equipment to be installed. Also worth noting is that engineering and design work becomes more complicated when companies try to design FGD and SCR systems that will not only work immediately upon start-up but also will be compatible with additional control systems that might later be installed at the same site in response to future regulatory programs requiring reductions in emissions of other pollutants (*e.g.*, mercury, particulate matter, and acid mist).

At a substantial percentage of affected sites -- including where FGD or SCR systems have not previously been installed because of site-specific complexities -- the need to consider and address these factors means that it will typically take 6 to 12 months to complete the engineering step of FGD and SCR installations. As explained in section 2.2.1 of the Implementation Schedules Report, taking 6 to 12 months (or longer) on this step is a prudent way to minimize risk and avoid cost overruns.

Once engineering and process design work is done -- and before actual construction can begin -- it is also necessary for plant owners to identify a number of qualified bidders (seeking multiple qualified bidders allows plant owners to take advantage of the competitive forces that can reduce the price of a project); solicit and review bids and then select the winning bids (a detailed process that, among other things, requires plant owners to host bidder meetings and site inspections as well as to review all submittals in detail); and negotiate final contracts (which can take considerable time, particularly where a plant owner and contractor have not previously worked together or if there are to be non-standard terms in the contract). As set out in sections 2.2.2 through 2.2.4 of the Implementation Schedules Report, it can take another 6 to 12 months to complete these steps.

In short, it often takes a much more extensive effort to "conduct an engineering review" than the four months suggested in the 2002 EPA Report. Indeed, as discussed in more detail in the accompanying Implementation Schedules Report and the comments of individual UARG members, completing these initial steps typically takes at least 12 months. And it is not unusual -- or unreasonable -- for companies to take even more time at the very beginning of such substantial projects to identify as broad a range of project pitfalls as possible and to try to address them then. Getting things "right" at the outset often means avoiding having to pay for mistakes all the way through the rest of the project.

2. A Construction Permit Is Only One of the Many Authorizations that Affected Plant Owners May Need.

Similarly, EPA underestimates the complexity of its second step: obtaining a construction permit. Rather than merely getting a single "construction permit" -- which arguably may have been a relatively quick-and-easy process at the time of the writing of the 2002 EPA Report -- those retrofitting FGD and SCR systems today must apply for and obtain numerous authorizations before they can undertake construction or start operating those new systems, including authorizations and permits that were not required a decade ago or that did not take as long to get at that time as they do today.

Consider, for example, the increased complexity involved in getting a CAA new source review ("NSR") preconstruction permit to cover "increased emissions" from the installation of

FGD and SCR systems. Such a permit may be needed because even though the operation of FGD and SCR units will significantly reduce emissions of SO_2 and NOx, respectively, the operation of that pollution control equipment may sometimes result in a "collateral increase" in the emission rate of a pollutant other than SO_2 or NOx. Thus, the operation of wet scrubbers and SCR -- while reducing SO_2 and NOx emissions -- may in some cases increase sulfuric acid mist by more than insignificant amounts. Also, operating low NOx burners will reduce NOx emissions but has been thought in some cases to increase carbon monoxide emissions.[26] In short, NSR preconstruction permitting requirements can be triggered by projects that will result in a significant net emissions increase of one or more "collateral" regulated pollutants.

Prior to late 2005, sources that installed control equipment did not thereby trigger the time-consuming NSR preconstruction permitting process because such projects were subject to the pollution control project exclusion ("PCP" exclusion) in EPA's NSR rules. In December 2005, a D.C. Circuit decision vacated the PCP exclusion. *New York v. EPA*, 413 F.3d 3 (D.C. Cir. 2005). As a result, the NSR permitting process may be triggered by a project to install an FGD, SCR, or LNB system if the operation of that control system may result in the increase of a pollutant other than the pollutant being controlled by the FGD, SCR, or LNB equipment. And an obligation to apply for and obtain an NSR permit, even if the permit itself does not require any additional emission controls, would delay installation of the new control system because of the elaborate and time-consuming procedures associated with NSR permitting.

For example, as discussed in section 2.2.5 of the Implementation Schedules Report and comments of UARG members, the process of obtaining an NSR permit before beginning

[26] Recent installations of LNBs, in conjunction with advanced combustion controls such as overfire air, have not increased carbon monoxide emission rates, but an assessment of this issue may still need to be undertaken before work can begin on the installation of an LNB system at a power station.

construction for FGD or SCR units, even if that process ultimately amounts to little more than a paper exercise, can add many months to the overall process. And if a full-blown NSR proceeding is needed -- perhaps to evaluate emissions of carbon dioxide and other greenhouse gases once the NSR process is scheduled to start applying to greenhouse gases in January 2011 -- that could add a year or more to the process. As also noted in the Implementation Schedules Report, although this was not a problem faced by companies installing pollution control projects in the first part of the last decade (due to the existence of the PCP exclusion), it is a problem now.

Also as noted in the Implementation Schedules Report, power plant owners must secure permits to address other environmental consequences of operating pollution control equipment, *e.g.*, permits for the treatment and/or storage of byproducts of both wet and semi-dry FGD systems, including the benign byproducts of those systems, such as gypsum. Securing a land use management permit for scrubber byproducts can take longer than four or even five years. *See* section 3 of the Implementation Schedules Report. Individual electric generating companies also point to other, more site-specific permitting issues that have arisen or are likely to arise when they seek permits to install FGD or SCR systems. For example, some companies report that the operation of pollution control equipment will result in discharges that will trigger the need for revisions to sources' Clean Water Act permits. Other companies point to the regulatory complications involved in locating, constructing, and operating plants (and associated pollution control equipment) in urban areas, where they face zoning challenges, restriction on the truck traffic related to such operations, and even height restrictions if equipment is to be located near an airport.

In addition, unmentioned in the 2002 EPA Report is that many electric utility companies cannot proceed with the installation of new FGD or SCR systems unless and until they receive authorization from their public utility commissions to do so. And as described in the Implementation Schedules Report and in comments of individual UARG members, this, too, can be a time-consuming process.

There is another "permit-related" point to keep in mind: source owners may not be able to start actual on-site construction of FGD and SCR systems until they have at least some of the above-listed authorizations in hand. In particular, this is the case where FGD and SCR installations are subject to the requirements of the NSR preconstruction permitting program. The NSR program limits the activities that source owners can conduct on-site prior to getting their final NSR permits. Thus, even though it may be possible to take some of the EPA-listed installation steps concurrently, some stages of the process -- including getting some of the needed regulatory approvals -- must be completed before work can begin on subsequent installation steps. And that can easily take many years, making this step alone a major impediment to the completion of FGD and SCR installations in less than 30 months.

3. The Actual Construction of FGD and SCR Systems at Existing Sites Will Take Longer than EPA Suggests.

EPA suggests that the construction phase of FGD and SCR systems can be accomplished in 20 months and 15 months, respectively.[27] As discussed below and in section 5 of the Implementation Schedules Report, however, EPA reached this conclusion based on its initial review of only a few installations that took place in the 1999-2001 timeframe. This was a time when relatively few installations were being done. (The FGD and SCR installations in that

[27] *See* 2002 EPA Report, at A-2 (Exhibit A-1, indicating 20 months for engineering, fabrication, delivery, and pre-hookup of FGD systems) and A-4 (Exhibit A-3, indicating 15 months for engineering, fabrication, delivery, and pre-hookup of SCR systems).

period were applied to only five GW of generation.) Also, those installations were largely special cases, *i.e.*, where shortcuts were taken in steps 1 and 2 and where there was an abundant labor force available to work on and oversee the construction of these systems. Now, 10 years later -- when scores of projects are underway simultaneously -- such shortcuts are not available or are not prudent to take. Also, with so many installations underway at the same time, there is no longer an oversupply of skilled labor to work on and oversee each project.

EPA's projected schedules also fail to take into account the site-specific complications that companies face at power stations. The earliest installations may have been at sites with sufficient space and access that construction could proceed in a straightforward way, without interfering with other plant operations. Today's installations are typically more challenging: they are at sites that were not retrofit in the first or second rounds of such activities because of the challenges they posed.

Specific examples of the challenges faced by power plant owners are summarized below and are also presented in the Implementation Schedules Report and in comments of UARG members. These real-world examples -- recent and numerous -- demonstrate that on average, actual construction schedules are likely to be closer to approximately two years for SCR systems (rather than the 15 months suggested by EPA) and three years (not 20 months) for FGD systems. And where there are greater complications at a site, construction schedules will be longer, perhaps much longer.

B. EPA Relies Upon Incomplete and Outdated Information in Concluding that FGD and SCR Retrofits Can Be Installed in a Total of Less than 30 Months.

As discussed below and in section 5 of the Implementation Schedules Report, the sole support for EPA's belief that FGD and SCR installations can be completed in a total of less than 30 months appears to be partial information from work at a few installations that do not reflect the variety of conditions one can expect to find at all the sites now being evaluated for control equipment retrofits. The implementation schedules presented in the Implementation Schedules Report (and discussed below) demonstrate that each site is unique and each site presents its own retrofit challenges. Also, the examples cited by EPA took place in the 1999-2001 timeframe, when (a) relatively few installations were being done (the SCR and FGD installations in that period were applied to only five GW of generation); (b) it was possible to take shortcuts in engineering, procurement, and permitting; and (c)an abundant labor force was available to work on and oversee the construction of these systems. Finally, the projects cited by EPA in support of its short installation deadlines may be incomplete. Additional information suggests that, in fact, some of the projects cited by EPA took longer to complete than suggested by EPA.

All of these factors were at play in the case of the Centralia FGD project, which was completed in November 2001. Although EPA claims that the installation was completed in only 24 months, information in the public domain indicates that it took a total of almost three years to do all the work to install the FGD system for Unit 1 at Centralia, and it took a total of 48 months to complete work on the second Centralia unit. In addition, Centralia's situation may be considered atypical, because the contract for the engineering and construction work at Centralia was part of a unique "partnering" agreement between the owners of Centralia and the contractor. As noted in the Implementation Schedules Report, this type of relationship can speed subcontracting and procurement activities, but it can also require significant upfront negotiations and arrangements, and there can be pitfalls to any approach that does not set aside adequate time prior to the start of construction to ensure that the project design and engineering are done right.

Similarly, the installation of Tampa Electric Company's FGD systems on Big Bend Units 1 and 2 -- also an early generation project -- appears to have taken more than 27 months to complete. Information in the public domain indicates that the 27-month schedule cited by EPA does not take into account that Tampa Electric took an additional 15 months before commencement of the installation work to apply for project permits and to conduct preliminary cost assessments and prepare the FGD procurement specification. This all indicates that the total amount of time needed to design, permit, and construct the FGD system was closer to a 42-month schedule than to a 27-month schedule. In addition, it was possible for Tampa Electric to accelerate the installation schedule at Big Bend by building upon the FGD installations that were already located at the site and in use at Big Bend Units 3 and 4. The reagent receiving and processing equipment and dewatering apparatus for the FGD equipment on Units 3 and 4 could – with some limited modification – be used in the new FGD installations at Units 1 and 2. Also, the land use permit for solid byproduct management already existed at Big Bend and likely received less scrutiny, which is very different from the situation faced today by those seeking permits for new, "greenfield" byproduct management sites.

There is even less information available concerning the SCR installations at Reliant Energy's (now NRG's) Keystone station in Pennsylvania and the AES Kintigh (previously Somerset) station in New York. These are the projects that EPA claims were completed in a total of approximately 21 months. Even if those projects did take less than 30 months to complete (and it is not clear that they did), there is nothing to suggest that they are typical of the construction challenges faced by those now undertaking SCR retrofits. For example, there is no evidence that the Kintigh project was competitively bid, and the contractor may have been selected because it had provided the boiler and plant ancillary components. This "non-traditional" approach to selecting a contractor did not entail the open, competitive bid process generally mandated for an investor-owned utility or public agency. Also, the non-traditional

Kintigh facility approach generally does not make sense for the much more complicated installations that companies now face. More complex projects require more effort to be taken up-front in the planning process -- before actual construction begins -- in order to minimize problems on the back end. Further, as noted in the Implementation Schedules Report, those involved in the Kintigh project faced far fewer regulatory obstacles 10 years ago than plant owners face today.

In short, the scant amount of data that EPA has offered in support of its highly accelerated installation deadlines is far outweighed by the vast amount of recent information to the contrary. This information is presented in the Implementation Schedules Report and in the comments submitted by individual UARG members. An overview of some of that information is presented below.

C. FGD Installations: Real-World Examples Demonstrate that EPA Has Substantially Underestimated How Long It Typically Takes To Retrofit FGD Systems at Power Plants.

A broad range of recent FGD retrofits is described in section 3 of the Implementation Schedules Report. Specifically, the Implementation Schedules Report presents information on a variety of single- and multiple-FGD retrofits, including those installations at Alabama Power Company's Barry Unit 5 (which took 53 months); the retrofit of an FGD system at Georgia Power Company's Hammond facility (which took 40 months); the retrofit of an FGD system at American Electric Power's ("AEP") Mountaineer facility (which took 42 months to complete); the installation of FGD at Salt River Project's Coronado Unit 2 (which took 44 months even though the plant owner was willing to pay additional local agency fees and assign contactors to expedite the permitting process and accelerate review); the retrofit of two FGD units at Duke Energy Company's Belews Creek Units 1 and 2 (which took a total of 49 months: 12 months of project work and 37 months of construction for the first unit to be operable); the installation of

FGD systems at Duke Energy's Cayuga Units 1 and 2 (54 months: 9 months of project work and 45 months of construction); and the installation of three or more FGD systems at Allegheny Energy's Hatfield's Ferry facility (45 months), First Energy's Sammis facility (56 months), and Alabama Power's Gorgas facility (61 months).

These examples demonstrate that in the most straightforward, uncomplicated situations, it may take as little as a total of 40 months to complete an FGD installation, but that at the most challenging sites, it can take more than 60 months (*i.e.*, five years). Typically, it takes a total of at least approximately 48 months to complete the retrofit of an FGD installation, but in many cases significantly more time than that is needed.

The case of Georgia Power's Plant Hammond installation is the example of a recent FGD installation that was completed in only 40 months. The single FGD module for the four boilers at Hammond could be installed on an abbreviated schedule due to several factors. First, the plant's owner was able to apply at Hammond the process and absorber design developed for other sites, which shortened the period for procuring contracts. Second, certain design tasks were accelerated as they were leveraged on previous, similar applications. Third, as described in greater detail in comments being filed separately by Southern Company, ample and accessible space was available to allow simultaneous construction of equipment such as the absorber and reagent preparation facilities. In contrast, the installation of a single FGD unit each at Alabama Power's Barry Unit 5 and Gaston Unit 5 took a total of 53 months and 64 months, respectively.

The complications -- and length of installation schedules -- increase with the construction of multiple FGD modules at a plant site. A notable case is that of Sammis Units 1-7. Figure 3-2 in the Implementation Schedules Report depicts the Sammis site layout, adjacent to the Ohio River, with Ohio State Route 7 located below the electrostatic precipitators and fabric filters built in the 1980s for these units, and three 800-MW FGD absorber towers. Flue gas from the entire station all 7 units is treated by these three absorber towers. (SCR process equipment is located on Units 6 and 7.) The extremely tight site -- bounded by the Ohio River and a rail line – constrained construction activities and contributed to an installation time of 56 months.

The retrofit of FGD at Alabama Power's Gorgas Units 8-10 is another example of the hurdles faced by source owners trying to install FGD systems at existing plant sites. Several reasons contributed to the fact that it took over five years to complete the work at Gorgas. First, the Gorgas retrofit was the owner's initial FGD project, which meant that significant time was required to do project engineering and to negotiate contracts. Second, the site required extensive modifications, including literally moving a small mountain to create adequate space for the FGD equipment. The limit on space forced the new stack to be constructed sequentially, and not in parallel with other equipment. Also, at the Gorgas site, it was necessary to make significant improvements to the plant's flue gas handling system in conjunction with the control equipment retrofit. All these factors (and others) contributed to the fact that it took a total of 61 months to complete the work at Gorgas

The Implementation Schedules Report also notes that retrofit schedules may be affected by whether the plant owner operates a large fleet of plants or only a few units. Owners in the latter category -- without the market power of, for example, large, multi-state operators -- are likely to have less leverage over suppliers and can expect longer installation times. The relatively small market presence of Dairyland Power Cooperative was at least one factor contributing to the 50-month installation schedule for retrofit of a semi-dry FGD unit at a Dairyland facility.

The common theme in all these retrofit examples is the extensive number of activities to be conducted within a limited, confined space, which requires many phases of the process to be conducted sequentially rather than in parallel. This produces FGD retrofit schedules of between 40 months and over 60 months.

D. SCR Installations: Real-World Examples Demonstrate that EPA Has Substantially Underestimated How Long It Typically Takes To Retrofit SCR Systems at Power Plants.

As noted above, relying on a small (and incomplete) amount of information concerning retrofits that two companies undertook a decade ago, EPA concludes that owners of EGUs can be expected to complete retrofits of SCRs at all power plant sites in only 21 months. The overwhelming amount of available data, however, demonstrates that it takes an average of a total of 39-40 months to complete such retrofits, and can -- at the most challenging sites -- take as long as 60 months to retrofit SCR at a power station.

The Implementation Schedules Report presents information on a variety of SCR retrofits. Examples of cases in which owners have retrofitted a single SCR reactor at a site include the work done at Alabama Power's Barry Unit 5 (50 months) and Gaston Unit 5 (40 months), AEP's Conesville Unit 4 (42 months), Duke's Marshall Unit 3 (46 months), Georgia Power's Hammond Unit 4 (28 months), and Gulf Power's Crist Unit 7 (42 months). Examples of multiple SCR retrofits at a site include First Energy's Sammis Plant (where retrofits on Units 6 and 7 required a total of 60 months); Alabama Power's Miller Station (where retrofits on Units 1 and 2 each took a total of 42 months and retrofits on Units 3 and 4 each took a total of 34 months); AEP's Kyger Creek Plant (where there was a retrofit of five SCR units, with the first operable within 31 months); Progress Energy's Crystal River Station (where SCR retrofits on Units 4 and 5 took 37 months); and Georgia Power's Scherer station project (which includes work on SCR for Units 1 through 4, and where the SCR system closest to completion is that for Unit 3, which is scheduled to be completed in a total of 50 months).

As in the case of FGD retrofits, the time it has taken to complete SCR installations has varied greatly due to a number of factors, the most important of which is the configuration of the plant site. For example, AEP was able to retrofit five SCR reactors at the Kyger Creek Station in a period of approximately 31 months because the units on which the SCR equipment was being retrofit were virtually identical to each other, allowing engineering to be expedited. Also, the modest generating capacity (220 MW per unit) did not require large quantities of material to be installed or relocated. The use of cranes within the compact site, and small distances over which to transfer materials, also contributed to expeditious installation. Although the plant site is constrained, the units are small and it was possible to stage the construction in a serial manner. At the other end of the spectrum, however, are the Sammis and Scherer retrofits, which took (or are taking) more than 50 months to complete because of the complexities of and congestion at those sites.

The Implementation Schedules Report also presents information on the time it takes to install low NOx burner systems at power plants. LNB systems are less complex than SCR or FGD systems; however, as is the case with FGD and SCR installations, the time it takes to complete an LNB installation will depend on conditions at the specific site, including details of the application, the engineering and unit preparation work, and the availability of an outage. A key factor in determining the installation schedule is the availability of LNB equipment. The limited number of qualified suppliers, and the special-purpose fabrication techniques required, can extend fabrication and delivery times. Also, there can be complications in the permitting process. At least one multi-state owner is anticipating a lengthier schedule for installing LNB equipment, due to concerns that have arisen in the permitting of the installations, where local regulatory agencies are questioning whether lower NOx emissions are inextricably linked to higher carbon monoxide emissions. section 4.2 of the Implementation Schedules Report presents schedule information concerning the low NO_x burners installed at Salt River Project's Coronado Unit 1 and Navajo Unit 3, and at units at Mississippi Power Company's Plant Daniel. This experience suggests project installations typically take a total of about 18 months -- far longer then the time between EPA's projected date for final action on the PTR and EPA's proposed compliance deadline of January 1, 2012.

E. Summary and Conclusions.

Solid information from individual UARG members and detailed information in the Implementation Schedules Report demonstrate that it now takes longer -- often much longer -- than 21 and 27 months to complete retrofits of SCR and FGD equipment, respectively. There are many reasons why FGD and SCR installations take as long as they do, including the complicated physical constraints posed by the sites at which the equipment will be installed (retrofits at any "simple" sites have likely already been done); the complexities of the overall permitting/authorization process that plant owners face today; and the high demand now for the skilled labor force needed to undertake these projects. The extensive amount of information presented in these comments and in the attached report, as well as information in comments from individual UARG members, refute any EPA claim that FGD and SCR installations can generally be conducted and completed in a total of less than 30 months.

There is also no basis for any suggestion that electric generating companies could cut installation times by 30% to 50% if only they had the will to do so. Such a "field of dreams" approach (something akin to "demand it and it will happen") does not apply to the construction of FGD and SCR systems. If electric generating companies could build such systems in less than 30 months, they would. For these companies, time is money, and the longer it takes to build a mandated project, the more it will cost. Electric generators may not -- and should not --

undertake FGD and SCR retrofits until it is clear that such installations are required and are prudent and consistent with fiduciary obligations to undertake. Once the companies commit to such projects, however, they are highly motivated to complete them quickly in order to minimize costs.

In summary, EPA has greatly underestimated the amount of time that it takes electric generating companies to design, permit, construct, and start up new FGD and SCR units. It will take longer than 30 months -- in many cases, considerably longer than 30 months -- for companies to complete the retrofits of FGD and SCR units at existing EGUs. Thus, it will not be possible for affected EGUs to achieve all the SO_2 and NOx emission reductions that -- under the terms of the PTR -- must be achieved by EPA's proposed January 2012 and January 2014 deadlines.

In light of this, EPA either should decide not to call for the steep additional emission reductions demanded by the PTR -- because such reductions are not, for reasons discussed in these comments and in comments of individual UARG members, necessary to reduce significant regional contributions to downwind nonattainment and interference with maintenance -- or should extend the PTR's compliance schedule by at least a two-year period beyond the proposed 2014 compliance date (plus an additional interval of time that reflects (i) any additional time that EPA takes to complete this rulemaking beyond mid-2011 and (ii) the reasonable period of time needed by states to implement emission budgets through SIP revisions after final promulgation of EPA's rule).

VI. EPA's Analysis Significantly Understates the Amount of Electric Generating Capacity that Would Have To Undergo FGD and SCR Retrofits in the 2012-2014 Period and the Associated Demands on Resources; Constraints on Labor Resources Make Compliance With the PTR's Timeline Impossible.

As noted above, EPA states in the preamble to the PTR that it "expects about 14 GW of FGD and less than 1 GW of SCR capacity to be retrofit for Phase 2 of this rule [*i.e.*, by January 1, 2014]." 75 Fed. Reg. at 45273/1. This projection omits the very substantial amounts of FGD and SCR retrofits that will be undertaken as part of the baseline when CAIR requirements are included in the baseline (as they should be, for reasons discussed elsewhere in these comments). In addition, because, as discussed in the preceding section of these comments, EPA has significantly underestimated the amount of time it takes to install these controls, a substantial number of retrofit projects that EPA assumes will be accomplished *by the beginning of 2012* will in fact not be completed until the critical 2012-2014 period (while, for the same reason, some of the retrofit projects EPA predicts will be completed after January 1, 2012, but before January 1, 2014, will in fact not be completed until after the latter date).

According to estimates prepared by UARG's consultants James Marchetti, J. Edward Cichanowicz, and Michael C. Hein,[28] a total of approximately 25 *new* GW of installed FGD capacity -- far higher than EPA's assumed 14 GW -- would be needed to meet the PTR's 2014 emission reduction requirements. In addition, their report projects that a total of about 8.2 new GW of installed SCR capacity would need to be installed by 2014. These numbers include emission control projects that will be needed under the 2014 base case, including CAIR. These 2014 numbers do not include retrofit capacity that would be installed by 2012.

[28] J. Marchetti, E. Cichanowicz, and M. Hein, "Schedule of Control Technology Retrofit To Meet EPA's Proposed Transport Rule" (Oct. 1, 2010). This report is attached hereto as Attachment II, and is incorporated by reference in these comments.

Marchetti, *et al.*, evaluated the likely operational dates for new FGD and SCR projects during this period. They used owner-announced dates where available (as they were for a minority of the projects). For other projects, they used an assumed project-start date of the third quarter of 2011 to reflect EPA's projected date of final promulgation of the PTR, and then assigned implementation schedules for the retrofit installations, applying information derived from the Implementation Schedules Report, as discussed in the previous section of these comments. The analysis shows that the majority of the projects could not be completed until well after January 2014; the largest number of FGD and SCR projects are projected to become operational at various dates between early 2015 and mid-2016.

This analysis then examined a key resource constraint considered by EPA in the CAIR proceeding, *i.e.*, the demand for boilermaker labor for retrofit installations. The analysis found that boilermaker demand for FGD and SCR installations can be accommodated *if* the realistic installation schedules applied from the Implementation Schedules Report are assumed. In contrast, if the retrofit projects were somehow otherwise able to be accomplished by 2014, as EPA assumes (a scenario that the Implementation Schedules Report shows is infeasible), then the resulting "logjam" of retrofit projects would require an amount of boilermaker hours that is far in excess of the boilermaker labor supply that was called on for EGU control retrofits in the 2008-2010 period. Thus, even if EPA's proposed compliance schedule could otherwise be met (and it cannot), there is no basis for concluding that a sufficient supply of skilled labor would be available to do the work necessary to meet the schedule.

Accordingly, EPA should recognize that under the PTR, the 2012-2014 period could be expected to involve far more FGD and SCR retrofits than its statement in the PTR preamble would suggest. Given the demands that will be imposed on retrofit resources, such as boilermaker labor, due to the congestion of control project installations during this highly compressed period, requiring the PTR's 2014 emission budgets to be met by accelerating retrofit projects that cannot realistically be projected to be completed by that year would both (1) be inconsistent with documented installation schedules (as described in the Implementation Schedules Report and in the previous section of these comments) and (2) be infeasible in any event in light of the available labor, and perhaps other resources, needed to accomplish these retrofits.

VII. Many of the Judgments and Policy Decisions Underlying the Structure of the Proposed Transport Rule Are Inappropriate and Unjustified.

EPA made several important judgments and policy decisions in developing the Proposed Transport Rule without explaining adequately the Agency's rationale. As discussed below, many of these decisions are inappropriate and must be adjusted before EPA proceeds further with this rulemaking.

A. EPA's Base Case Modeling Should Have Included CAIR.

The Proposed Transport Rule fails to account properly for post-2005 emission reductions and air quality improvements resulting from CAIR. *See* 75 Fed. Reg. at 45233/3. EPA's decision to assume that CAIR is not in effect for its analysis of the 2012 and 2014 base cases has the effect of greatly overestimating EGU emissions during those periods. EPA should have included CAIR in its base case because it remains binding law pending the promulgation and effective date of a replacement rule. The D.C. Circuit granted EPA's petition to remand CAIR without vacatur, holding that "notwithstanding the relative flaws of CAIR, allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values covered by CAIR." 550 F.3d at 1178. By the terms of the court's opinion on rehearing, CAIR will be in place until a replacement rule is implemented. Thus, there is no time during which neither CAIR nor a replacement rule will be effective.

In the proposed rule's preamble itself, EPA recognizes what it could hardly dispute -- that CAIR has yielded substantial emission reductions. For example, according to the proposed rule, the most recent monitoring available (2006-2008) "shows significant improvement[]" in $PM_{2.5}$ ambient air quality, and "EPA believes that a great deal of the improvement in $PM_{2.5}$ annual and 24-hour concentrations in the eastern U.S. can be attributed to EGU SO_2 reductions achieved due to the CAIR." 75 Fed. Reg. at 45219/3; *see also id.* at 45220/1-3 (noting that "EPA believes that there would be substantially more nonattainment counties for both the annual and 24-hour standards if the CAIR were not in effect," and crediting a variety of programs with improved ozone air quality in the years since EPA published CAIR). There can be no dispute that CAIR, together with other programs, has had significant effects in reducing NAAQS design values.

Additionally, in both the NOx SIP Call and CAIR rulemakings, EPA took account of other regulations in evaluating downwind air quality. *See* 63 Fed. Reg. at 57377/1 (NOx SIP Call) (EPA's "analytical approach assumes that downwind areas implement all required controls and receive the benefit of reductions from Federal measures, and yet have a residual nonattainment problem."); 69 Fed. Reg. at 4581/2-3 (CAIR proposed rule) ("In modeling the 2010 and 2015 'base cases,' we took into account adopted State and Federal regulations (*e.g.*, mobile sources rules, the NOx SIP Call) as well as regulations that have been proposed and that we expect will be promulgated before [CAIR] is finalized.") In the Proposed Transport Rule, EPA purportedly took into account all other federal rules promulgated as of December 2008, *except for CAIR.*[29] 75 Fed. Reg. at 45233/3. It is difficult to understand why EPA made the decision to ignore CAIR for purposes of the Proposed Transport Rule.

EPA's brief explanation of why it decided to ignore CAIR in modeling the base case for the proposed rule, which it characterizes as "a unique situation," *id.* at 45233/3, is baffling. EPA acknowledges that "EPA has been directed to replace the CAIR; yet the CAIR remains in place and has led to significant emissions reductions in many states." *Id.* at 45233/3. Then, it says that "EPA cannot prejudge at this stage which states will be affected by the rule," and goes on to note that sources in states that are regulated under CAIR but not under the Transport Rule may increase their emissions once CAIR expires. *Id.* at 45233/3. Yet there are very few of those states, and the existence of a minority of such states hardly justifies wholesale disregard of CAIR reductions.[30] Moreover, EPA has not shown that emission increases in these few states are likely, or indeed that such increases would even be permitted under state law. In any event, many sources located in states that were regulated under CAIR but are not proposed to be regulated under the Transport Rule have gone to great expense to install controls to comply with CAIR. They are very unlikely to dismantle them or to discontinue use of them to the point that their emissions return to pre-CAIR levels. Finally, $PM_{2.5}$ and ozone concentrations have declined substantially in recent years, due not only to CAIR but also to a combination of other

[29] In addition, EPA has failed to include known local emission reductions in, for example, nonattainment areas. By ignoring the air quality benefits from those controls, EPA overestimates the number of downwind nonattainment and maintenance monitors and inflates the design values of those monitor sites that are above the NAAQS, thereby overstating the emission transport problem that the Transport Rule is designed to resolve.

[30] *Compare* 70 Fed. Reg. at 25167/1 *with* 75 Fed. Reg. at 45215/2. With respect to the annual $PM_{2.5}$ NAAQS, only Mississippi and Texas were regulated under CAIR but are not proposed to be regulated under the Transport Rule. With respect to the 8-hour ozone NAAQS, only Iowa, Massachusetts, Missouri, and Wisconsin were regulated under CAIR but are not proposed to be regulated under the Transport Rule.

programs, and are expected to continue declining in the future. *See* EPA's Trends Report at 1-2. While it may be conceivable that some limited increases in emission levels could occur due to discontinuation of CAIR requirements in some states, it is far less realistic to assume that CAIR is no longer in effect than to assume that it remains in effect. EPA should recalculate the 2012 and 2014 base cases to take CAIR into account.

B. EPA Should Return to Its "Monitored-Plus-Modeled" Approach.

EPA should not have abandoned use of the "monitored-plus-modeled" approach that it used in CAIR and the NOx SIP Call rule to determine downwind nonattainment areas to be addressed.[31] EPA provides no justification in its proposal for its decision to jettison this approach. The monitored-plus-modeled approach is preferable to the approach used in the Proposed Transport Rule because the inclusion of monitored data helps provide a grounding in real-world air quality that is lost in EPA's novel "modeling-only" approach that relies exclusively on IPM projections. It is by no means clear that IPM is even fit to be used in the manner in which EPA used it in developing the Proposed Transport Rule. IPM is a least-cost economic model that operates on a regional scale and is not designed to replicate real-world scenarios in specific locations. *See* section VIII *infra* for further discussion of IPM. Furthermore, LADCO specifically recommended that EPA continue to use the "monitored-plus-modeled" approach. LADCO Letter, attachment at 2. Equally important, the use of monitored data for this purpose was never challenged or criticized in *North Carolina v. EPA*.

If EPA had considered current monitored data, it would have found that many of the areas that it projects, in the Proposed Transport Rule, to be downwind nonattainment areas in

[31] *See* 62 Fed. Reg. 60318, 60324/3-60325/1; 63 Fed. Reg. at 57375/1-2 (explaining and adopting the "monitored-plus-modeled" approach in the NOx SIP Call); 69 Fed. Reg. 4566, 4581/1-2; 70 Fed. Reg. at 25174/2 (explaining and adopting for CAIR the "monitored-plus-modeled" approach used in the NOx SIP Call).

fact currently have air quality that is in *attainment* of the ozone and/or $PM_{2.5}$ NAAQS. For example, nearly 60 percent of the monitoring sites that EPA projects to be in nonattainment areas for the 24-hour $PM_{2.5}$ NAAQS in 2012 in fact are in either currently designated *attainment* areas or areas that have air quality that is in attainment of that NAAQS, according to an EPA determination after notice-and-comment rulemaking. *See* Attachment III hereto at Table II for details.[32] Likewise, EPA has determined or proposed to determine that approximately 20 percent of the monitoring sites that EPA projects to be in nonattainment areas for the annual $PM_{2.5}$ NAAQS and approximately 10 percent of the sites that EPA projects to be in nonattainment areas for the 8-hour ozone NAAQS are in areas that currently have air quality that *meets* the relevant NAAQS. *See id.* at Tables I and III respectively for details.[33] Given the prevailing downward trend in ambient concentrations, it is most unlikely that these areas should be viewed as downwind problem areas.

EPA should return to its monitored-plus-modeled approach in this rulemaking, or at a minimum, should explain the basis for its departure from that approach, including how its

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[32] According to EPA's Greenbook, http://www.epa.gov/oar/oaqps/greenbk/, of the 92 monitoring sites that EPA projects will be in nonattainment areas in 2012 for the 24-hour $PM_{2.5}$ NAAQS, 52 are in areas currently designated as attainment areas for that NAAQS, and EPA recently issued a final determination that an additional area (Jefferson County, Alabama) with two sites has air quality in attainment of that NAAQS.

[33] With respect to the annual $PM_{2.5}$ NAAQS, EPA has issued either a proposed or final determination that 6 of the 32 sites that EPA projects in the PTR will be in nonattainment areas in 2012 currently are in areas with air quality in attainment of the NAAQS. With respect to the 8-hour ozone NAAQS, EPA has issued a final determination that Baton Rouge, Louisiana, one of the 11 areas that EPA projects in the PTR will be nonattainment in 2012, currently has air quality in attainment of the NAAQS.

reasoning has changed and why it believes that current monitored air quality data is not relevant to this rulemaking.[34]

C. **EPA's Proposed Air Quality Contribution Threshold Is Flawed.**

EPA proposes to use an air quality contribution threshold based on a percentage -- specifically, one percent -- of the NAAQS for annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and 8-hour ozone to determine whether an upwind state should be included in the Transport Rule program with respect to each of those NAAQS. *See* 75 Fed. Reg. at 45237/1-45238/1. EPA explains in the preamble to the proposed rule that it chose to deviate from the approach it used in CAIR with respect to $PM_{2.5}$ by using here a two-digit value rather than a single-digit value and "decoupl[ing] the precision of the air quality thresholds [from] the monitoring reporting requirements." *Id.* at 45237/3.

Although EPA properly proposes to avoid setting a zero contribution threshold for the current 24-hour $PM_{2.5}$ NAAQS, *see id.*, and to avoid setting a precedent for a 0.1 μ/m^3 contribution threshold if the annual $PM_{2.5}$ NAAQS in the future is reduced to some value lower than the current NAAQS but higher than 10 μ/m^3 (*e.g.*, 14 μ/m^3), *see id.*, EPA's proposed approach ignores the limits of the capability of its air quality modeling techniques -- and of ambient monitoring -- to meaningfully detect and measure ambient-air contributions at the extremely low levels represented by one percent of current or possible future NAAQS. For example, the numerical values that result from application of EPA's one-percent contribution

[34] EPA also must consider the results of air quality modeling and other analyses performed for the Midwest Ozone Group ("MOG") and reported in MOG's comments filed in this docket, dated October 1, 2010. MOG's comments show, among other things, that existing controls, including CAIR, are projected to resolve most of the downwind $PM_{2.5}$ and ozone air quality problems in at least a large section of the PTR domain by no later than 2014. Moreover, MOG's comments demonstrate that, much as is shown in UARG's comments, there are substantially fewer existing nonattainment problems in the PTR domain than EPA's proposal suggests.

threshold approach to the current NAAQS -- *i.e.*, 0.15 μ/m^3 for annual $PM_{2.5}$, 0.35 μ/m^3 for 24-hour $PM_{2.5}$, and 0.8 ppb for 8-hour ozone -- are so low that they are likely below the detection capability of existing modeling and measurement tools. For that reason, it is far from clear that these thresholds could be deemed to reflect a "measurable contribution" to downwind nonattainment and maintenance problems, as required by the D.C. Circuit. *Michigan v. EPA*, 213 F.3d at 684 (" . . . *EPA must first establish that there is a measurable [air quality] contribution.* Interstate contributions cannot be assumed out of thin air.") (emphasis in original). At a minimum, EPA should provide, in a supplemental notice of proposed rulemaking, a technical justification for these very low thresholds as representing meaningfully measurable air quality contributions.

Equally troubling is EPA's indication that it may be planning to use this same percentage-based approach in any future version of the Transport Rule to address possible future NAAQS. *See* 75 Fed. Reg. at 45237/3 (noting that one of the considerations favoring the one-percent contribution threshold approach is that "the approach is readily applicable to any current and future NAAQS"). Application of this approach to potential future ambient standards that may be even lower than the current NAAQS would produce even less meaningful thresholds. It makes no sense for contribution thresholds to change based exclusively on changing NAAQS levels, irrespective of the capabilities of modeling and measurement technologies at the time the thresholds are established.

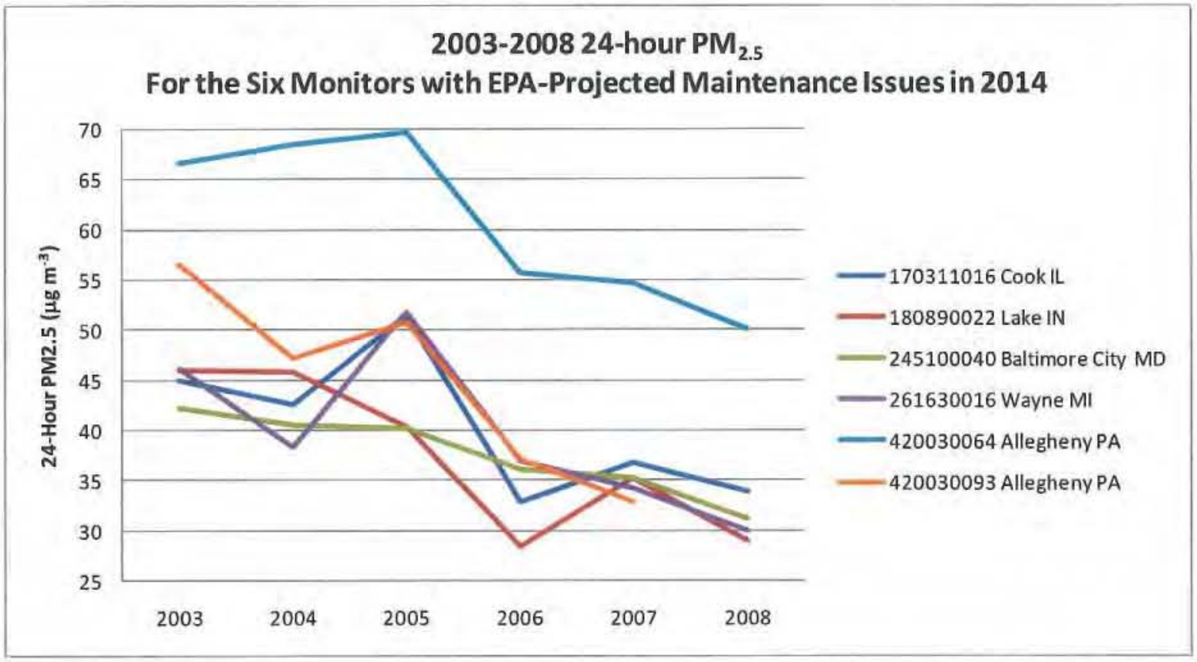
Accordingly, UARG objects to EPA's proposal to use its percentage-based air quality contribution threshold approach in the current rulemaking -- or in any future interstate-transport rulemaking -- in the absence of a robust technical justification that the resulting thresholds reflect meaningful, and truly measurable, air quality contributions, consistent with the D.C. Circuit's directive in *Michigan v. EPA*.

D. The Method EPA Used To Determine "Interference With Maintenance" in the Proposed Rule Overestimates Actual Future Design Values.

The method that EPA used in the Proposed Transport Rule to identify downwind monitors to be included in its "interference with maintenance" analysis overstates actual future design values, probably by a substantial amount. EPA explains in the preamble to the proposed rule that it determined maintenance sites based on the future-year maximum design values, and nonattainment sites based on future-year five-year weighted average annual design values. (Thus, all nonattainment sites were, in effect, also maintenance sites because the maximum design value is always greater than or equal to the five-year weighted average.) 75 Fed. Reg. at 45247/2-3, 45249/3, 45252/2-3. By using the *future-year maximum* $PM_{2.5}$ design values as the basis for the "interference with maintenance" analysis, EPA fails to take account of the strong nationwide trend toward decreasing design values and improving air quality, which the Agency has said it expects to continue. *See* EPA's Trends Report at 1-2. One can only assume that EPA's expectation is based on expected continuing declines in emission levels and that the recent improving air quality has been largely driven by recent declines in emission levels resulting from controls.

This approach had a major effect on the design of the proposed rule. For example, EPA proposed to require certain states (the "group 1 states") to meet additional SO_2 emission reduction requirements beginning in 2014, beyond the reduction requirements for 2012, because of perceived maintenance problems at six specific downwind monitors. Southern Company, a

UARG member, plotted the 98th percentile design values for 24-hour $PM_{2.5}$ from 2003 to 2008[35] based on EPA's 2006-2008[36] Design Value spreadsheet for 24-hour $PM_{2.5}$, *available at* http://www.epa.gov/oaqps001/airtrends/pdfs/dv_pm25_2006_2008rev102809.xls. The downward trend in design values at these six monitors is clear:



It is easy to see that basing a determination of a maintenance problem at any one of these six monitors on the future-year *maximum* $PM_{2.5}$ design value would almost inevitably overstate the air quality design value at that monitor and, based on the strong downward trend in design values, would most likely result in a false determination. There is no reason to believe that the trend that is apparent in the design values at these six monitors is unusual. In fact, a similar trend

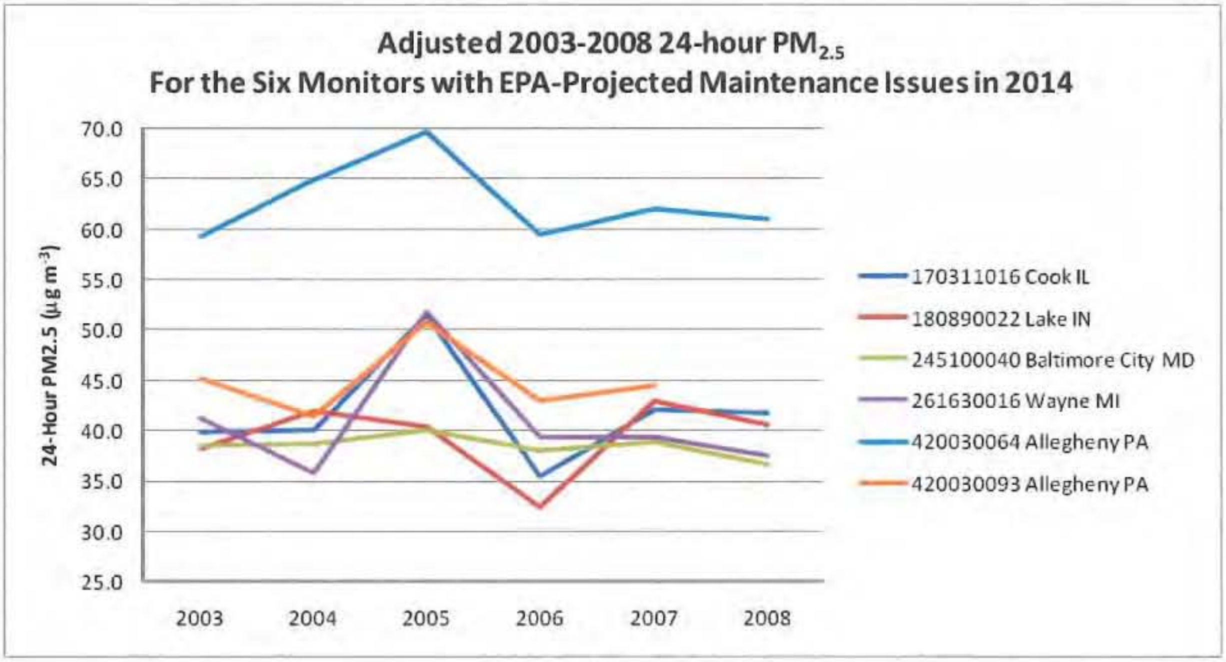
[35] Although the three base periods used by EPA were 2003-2005, 2004-2006, and 2005-2007, 75 Fed. Reg. at 45247/2, 45249/2, 45252/2, this plot includes data not only for those years but, for additional context, 2008 as well.

[36] The spreadsheet contains design values from 1999-2001 through 2006-2008. *See* http://www.epa.gov/oaqps001/airtrends/values.html.

is likely to exist at most of the downwind monitors evaluated in the proposed rule. It is especially important for EPA to set forth a justifiable methodology for determining maintenance issues since EPA's proposal in effect establishes elimination of all interference with maintenance as the driving factor for the PTR's emission reduction requirements. Therefore, EPA should revisit its method for identifying downwind maintenance problems, justify its reasoning for choosing a particular method, and revise its analysis to make it more representative of current and likely future air quality and to take account of the downward trend in design values.

One alternative approach that EPA could take to determine maintenance issues would be to remove the trend in the data where air quality is improving over the five-year period, prior to determining the maximum three-year design value. Briefly, this method would involve determining the linear fit to the five-year (*i.e.*, the 2003-2007) air quality data, calculating the residual values from the difference between the linear fit and the observed values, and then adding the residual values to the average of all five years of data (2003-2007 values). The result would be an adjusted five-year time series with no trend, which would have the same average and the same five-year weighted mean design value as the original observations. This result would still capture the inter-annual variability in air quality at sites with improving air quality without biasing the projected "maintenance" value upward for areas where emission reductions are already resulting in air quality improvement, and would better identify sites where maintenance may genuinely be an issue. The plot below shows the effect of applying this methodology to the data at the six monitors shown in the plot above.[37]

[37] This plot includes 2008 values for context -- they were not used for adjusting the data.



As this plot depicts, the downward slope at all of these sites has been removed, but the inter-annual variability remains. Table VII-1 below shows the estimated effect of applying this methodology to the projected 2012 base case design values for these six sites. This approach provides a more reasonable estimate of the threshold that may be necessary for maintenance of attaining air quality, in that it eliminates an inadvertent penalty for having made progressive improvements in air quality through emission reductions. Furthermore, it provides a better estimate of inter-annual variability that would be due to inter-annual meteorological and/or emissions variability.

Table VII-1						
			2012 Projected Values			
			5-Year (EPA Method)		5-Year Adjusted (Alternative Method)	
Receptor Monitor ID	Receptor County	Receptor State	Wtd Mean DV	Max DV	Wtd Mean DV	Max DV
170311016	Cook	IL	41.0	44.1	41.0	41.6
180890022	Lake	IN	37.3	42.1	37.3	38.4
245100040	Baltimore City	MD	36.3	38.3	36.3	36.6
261630016	Wayne	MI	40.6	43.0	40.6	41.2
420030064	Allegheny	PA	58.8	62.3	58.8	59.0
420030093	Allegheny	PA	41.1	46.2	41.1	41.3

E. The Process EPA Used To Classify Certain States as "Group 1" States Is Inadequately Explained and Misguided.

In the Proposed Transport Rule, EPA describes its process for classifying states as "group 1" and "group 2" states for $PM_{2.5}$ as follows:

> EPA used the air quality assessment tool to analyze the impact of requiring all states linked to the downwind state site with an air quality problem, as well as the downwind state, to reduce emissions consistent with the levels discussed for 2012 . . . previously. The air quality assessment tool shows that those 2012 reductions will resolve the nonattainment and maintenance problems for all of the areas to which [certain] states [referred to as group 2 states] are linked . . . . EPA also assessed whether, in 2014, the combination of this level of reduction from the group 2 states and the remaining states (referred to as group 1 states) continued to result in all downwind areas—except for Allegheny County, Pennsylvania—fully addressing their nonattainment [and/or] maintenance problems, and determined that it did.

75 Fed. Reg. at 45282/1-2. Conversations between UARG members and EPA staff have revealed that, while not untrue, this description is materially incomplete and potentially misleading, especially with respect to the analysis that led to classification of the group 1 states. A representative of Southern Company contacted EPA's Clean Air Markets Division on September 3, 2010, and again on September 10, 2010, requesting clarification regarding how

EPA classified individual states as group 1 or group 2 states. A representative of the Clean Air Markets Division explained the process as follows.

EPA first determined which downwind monitors were classified as nonattainment and/or maintenance for $PM_{2.5}$ based on the projected 2012 base case air quality, and then identified upwind states that were "linked" to these monitors. This step in EPA's methodology determined which states were included in the Transport Rule for $PM_{2.5}$, at least as group 2 states, based on their significant contribution to nonattainment or interference with maintenance. Next, EPA used its air quality assessment tool and the emission changes resulting from the 2014 cost curves to evaluate how air quality at the nonattainment and maintenance monitors would change in response to emission reductions from "linked" upwind states, assuming a linear relationship between reductions in the upwind states' emissions and reductions in their respective contribution to projected ambient concentrations at the downwind monitors. EPA evaluated each monitor independently, considering only emission reductions from "linked" upwind states and the state in which the monitor is situated. EPA found that the 24-hour $PM_{2.5}$ NAAQS was controlling because most annual $PM_{2.5}$ problems were resolved at relatively low dollars-per-ton thresholds, while 24-hour $PM_{2.5}$ problems were more likely to persist at higher cost thresholds. EPA focused on the maintenance monitors and did not consider the nonattainment monitors separately because of the way that nonattainment and maintenance sites were determined.[38]

Using its air quality assessment tool, EPA determined that, in 2014, there were six monitors that still showed maintenance problems at approximately $300-$400 per ton that, with

[38] As described above, EPA determined maintenance sites based on the future-year maximum $PM_{2.5}$ design values, and nonattainment sites based on the future-year five-year weighted average annual $PM_{2.5}$ design values. Thus, all nonattainment sites were also maintenance sites. 75 Fed. Reg. at 45247/3. *See* section VII.D *supra* for comments regarding the manner in which EPA determined maintenance sites.

the exception of one in Allegheny County, Pennsylvania, could be eliminated at $2,400 per ton or less. EPA then decided that the states linked to those six monitors that continued to have maintenance problems at higher dollar-per-ton levels should be required to make additional emission reductions, and EPA used the 2012 base case to determine which upwind states were "linked" to those six remaining monitors. EPA classified upwind states that, in the 2012 base case, were linked to those six monitors as group 1 states and classified upwind states not linked to those six monitors as group 2 states. It appears that this was the sole determinant for classifying states as group 1. Strikingly, according to EPA's Clean Air Markets Division, in determining group 1 or group 2 status in 2014, *EPA ignored the air quality benefits that would accrue in 2012 and 2013 from the emission reductions required by the Transport Rule during those years and from state rules, consent decrees, and other requirements that will result in additional emission reductions by 2014.*

This illogical decision not to consider the results of reductions required beginning in 2012 in projecting remaining maintenance problems in 2014 demonstrates a complete disconnect in the Agency's analysis. EPA characterizes its Proposed Transport Rule as having two "phases." 75 Fed. Reg. at 45215/3. It makes no sense to evaluate phase II of the proposal in isolation, ignoring the projected effects of phase I (and other emission reduction requirements applicable in the period leading up to 2014). EPA's approach is made worse by the Agency's decision to ignore the effects of CAIR and local controls for purposes of modeling. *See* section VII.A *supra* and section VII.F *infra*. Had EPA considered the emission reductions that would result from the 2012 compliance deadline and other controls, it is likely that the supposed maintenance problems projected at most or all of these six monitors in 2014 would be shown not to exist, even if the Agency had continued to ignore the effects of CAIR. As these comments note above, air quality has been improving steadily in recent years, and, consistent with that nationwide trend, 24-hour $PM_{2.5}$ concentrations at all six of the monitors at issue show a strong downward trend. *See* graph showing the 98th percentile design values for 24-hour $PM_{2.5}$ at these six monitors from 2003-2008 at section VII.D *supra*. EPA should redo and publish for public comment its analysis of 2014 air quality by including consideration of the emission reductions required in 2012 and 2013 under the proposed rule and other applicable requirements. A balanced analysis of this issue is likely to remove any justification for imposing more stringent SO_2 requirements on certain states in phase II of the program.

F. EPA's Determinations of "Significant Contribution" and "Interference with Maintenance" Improperly Presuppose Upwind-State EGU Emissions as the Primary Cause of Downwind Nonattainment Problems and Inappropriately Underestimate the Contribution of Local Sources from a Variety of Emission Sectors.

1. EPA's Approach Places an Undue and Unlawful Burden on Sources in Upwind States To Reduce Emissions.

EPA's Proposed Transport Rule improperly puts all or most of the emission reduction burden on sources located outside the local nonattainment or maintenance area. Indeed, EPA admits as much. In the preamble to the proposed rule, EPA explains that "EPA continues to believe that a strategy based on adopting cost effective controls on sources of transported pollutants as a first step will produce a more reasonable, equitable, and optimal strategy than one beginning with local controls." 75 Fed. Reg. at 45226/3. EPA recites several reasons for its decision to assign "substantial responsibility" to upwind states to decrease their emissions in an effort to decrease or eliminate nonattainment in downwind states, 75 Fed. Reg. at 45272/1, but none can justify EPA's failure to adhere to the terms of the CAA.

Section 107(a) of the Act states that "[e]ach State *shall have the primary responsibility* for assuring air quality within the entire geographic area comprising such State." 42 U.S.C. §

7407(a) (emphasis added). EPA's proposal instead would impose on upwind states the "primary responsibility" for assuring air quality in the downwind states that contain the nonattainment and maintenance sites, in direct contradiction to this fundamental principle of the CAA. EPA is bound by the terms of the Act to recognize that the primary responsibility for attaining and maintaining air quality standards in a given state is to be borne by that state.

One consequence of this principle is that EPA was required to account for local controls in the first instance. EPA did not comply with this requirement. For example, EPA states that in the development of the future year emission scenarios, "[f]or nonEGU point and nonpoint stationary sources, any local control programs that may be necessary for areas to attain the annual $PM_{2.5}$ NAAQS and the ozone NAAQS are not included in the future base case projections." 75 Fed. Reg. at 45241/2.[39] Proper accounting for local controls may well have resulted in different emission budgets.

EPA gave recognition to the terms of section 107(a) in the NOx SIP Call rule and CAIR, at least to a certain degree. Both the NOx SIP Call rule and CAIR were based on the concept of residual nonattainment -- that downwind states containing designated nonattainment areas would be unable to reach attainment in those areas through the use of local controls alone. *See* 63 Fed. Reg. at 57377/1-2 ("The fact that a nonattainment problem persists, notwithstanding fulfillment of CAA requirements by the downwind sources, is a factor suggesting that it is reasonable for the upwind sources to be part of the solution to the ongoing nonattainment problem."); 70 Fed. Reg.

[39] EPA stated in its technical support document ("TSD") on "Emissions Inventories" that "[t]his is because the nonattainment areas for the 1997 $PM_{2.5}$ and ozone standards were not announced until 2004 and 2005 respectively, and the corresponding [SIPs] were not due until 2007 and 2008, thereby preventing the inclusion of these local measures in the 2005 emissions inventory." EPA, "Emissions Inventories" TSD at 11. The unavailability of this information in 2005, however, does not explain why EPA has not taken it into account in the future base case projections.

at 25184/3 (explaining that regional emission reductions are necessary because "it would be difficult if not impossible for many nonattainment areas to reach attainment through local measures alone"). In the final CAIR, for example, EPA explained that it evaluated emission control options to determine the average emission reductions that were possible in nonattainment areas using local controls, and then determined, based on this analysis, that reductions from sources in upwind states were necessary -- *in addition to local controls* -- in order for downwind states to reach attainment. 70 Fed. Reg. at 25194/1-2. As mentioned above, this reasoning gives at least a degree of recognition to the requirement of section 107(a), discussed above, that states bear the primary responsibility for assuring air quality within their borders. EPA's failure to do so here requires the Agency to revise and reissue the proposed rule based on a proper assessment of the role of local controls in NAAQS attainment strategies.

2. EPA's Air Quality Assessment Improperly Overestimated the Marginal Benefit of Emission Reductions Above Relatively Low Dollar-Per-Ton Levels.

EPA's air quality assessment for the proposed rule did not properly consider the very limited nature of the reductions in the estimated number of projected nonattainment and maintenance sites that result from increasing the marginal cost per ton of EGU SO_2 controls above comparatively low levels such as \$300 or \$400 per ton. *See* Tables IV.D-3 and IV.D-4, 75 Fed. Reg. at 45280, which are reproduced below.

TABLE IV.D–3—ESTIMATED NUMBER OF NONATTAINMENT AND/OR MAINTENANCE MONITOR SITES IN 2014 FOR ANNUAL $PM_{2.5}$

[As a function of SO_2 cost-per-ton levels]

Marginal cost per ton	2014 Number of remaining nonattainment monitor sites	2014 Number of remaining nonattainment and maintenance monitor sites
>$0	12	19
>$100	3	6
>$200	2	3
>$300	2	3
>$400	1	2
>$500	1	2
>$600	1	1
>$800	1	1
>$1,000	1	1
>$1,200	1	1
>$1,400	1	1
>$1,600	1	1
>$1,800	0	1
>$2,000	0	1
>$2,400	0	1

EPA's Table IV.D-3 indicates that, with respect to the annual $PM_{2.5}$ NAAQS, two nonattainment monitor sites would remain in 2014 at $200/ton and $300/ton and only one would remain at $400/ton, compared with 12 at $0/ton. EPA projects that the one remaining nonattainment monitor would reach attainment only at $1,800/ton. Similarly, EPA projects that only three nonattainment and maintenance monitors would remain in 2014 at $200/ton and $300/ton and two would remain at $400/ton, compared with 19 at $0/ton and six at $100/ton.

TABLE IV.D–4—DAILY AIR QUALITY IMPACTS VS. SO_2 COST PER TON LEVELS IN 2014

Marginal SO_2 cost per ton	Number of remaining nonattainment and maintenance monitor sites	Air quality improvement (average µg/m^3 Reduction) relative to 2014 base case (zero dollars/ton) All sites in 2012 base	6 selected sites *	3 selected sites **
>$0	64	0.0	0.0	0.0
>$100	16	3.7	2.0	1.8
>$200	12	4.4	2.4	2.1
>$300	8	4.7	2.6	2.3
>$400	*6	5.0	2.9	2.6
>$500	6	5.1	3.0	2.6
>$600	6	5.3	3.1	2.8
>$800	6	5.4	3.3	2.9
>$1,000	6	5.6	3.4	3.0
>$1,200	6	5.7	3.4	3.0
>$1,400	6	5.8	3.5	3.1
>$1,600	5	6.0	3.6	3.2
>$1,800	4	6.2	3.7	3.3
>$2,000	**3	6.4	3.9	3.4
>$2,400	1	6.8	4.1	3.7

*The six sites are: Allegheny County, PA (2 sites); Baltimore County, MD; Wayne County, MI; Lake County, IN; Cook County, IL.
**The three sites are: Lake County, IN; Cook County, IL; Allegheny County, PA.

Table IV.D-4 indicates that, with respect to the 24-hour $PM_{2.5}$ NAAQS, EPA projects that eight nonattainment and maintenance monitors would remain in 2014 at $300/ton and that six would remain at $400/ton, compared with 64 at $0/ton. EPA projects that those six monitors would remain nonattainment or maintenance until the $1,600/ton level, at which they would drop to five, and one would remain at $2,400/ton.

Analysis of these cost curves is complicated by the fact that, in EPA's analysis, few additional emission reductions are available at each additional cost increment. This drives the analysis upward in pursuit of the modest benefits available at each cost increment. Consideration of local controls would make this analysis far more realistic.[40] A proper analysis, particularly one conducted pursuant to an iterative process, likely would have produced very different and less stringent budgets.[41] EPA should conduct such an analysis and issue it for public comment in a supplemental notice of proposed rulemaking.

Indeed, much of this work has already been done. Comments submitted by Southern Company include the results of an analysis conducted by replicating EPA's data and air quality assessment tool. That analysis shows that key indicators of air quality remain essentially unchanged under the Proposed Transport Rule despite differences in aggregate and statewide

[40] UARG also notes that, by basing 2012 unit allocations on each unit's share of the lower of 2009 emissions or projected 2012 emissions for the state where the unit is located, 75 Fed. Reg. at 45309/3, EPA failed to take account of the additional overall cost of the program attributable to the de facto loss of the value of allowances that would have been generated as a result of early reductions under CAIR.

[41] Although the cost per ton levels that EPA selected are unreasonably high, UARG supports EPA's decisions not to select a NOx cost breakpoint above $500/ton and not to select an SO_2 cost breakpoint above $2,000/ton. 75 Fed. Reg. at 45281/1-3. Although UARG believes that these breakpoints are also unreasonably high, they are more reasonable than other breakpoints that EPA considered or may have considered. However, as discussed in this section of the comments, had EPA considered the effects of reducing SO_2 emissions before considering the effects of reducing NOx emissions, EPA would have concluded that annual NOx emission reduction obligations to address $PM_{2.5}$ should not have been included in the proposed rule at all.

emission reduction amounts required under the proposed rule compared to those required under CAIR. This analysis provides a basis for concluding that the Proposed Transport Rule will produce a level of air quality that is substantially the same as that which would be produced by continued implementation of CAIR. Table VII-2 below, which was created by Southern Company, compares (i) the number of nonattainment and maintenance sites projected to remain after implementation of the emission reductions required beginning in 2012 under the PTR to (ii) the number of nonattainment and maintenance sites projected to remain after implementation of phase I of CAIR, and the number of nonattainment and maintenance areas projected to remain after implementation of the emission reductions required beginning in 2014 under the PTR to the number of nonattainment and maintenance areas projected to remain after implementation of phase II of CAIR.

Table VII-2

		Number of Downwind Monitors	
NAAQS	**Scenario**	**Nonattainment**	**Maintenance**
24-hr $PM_{2.5}$	2012 remedy	1	9
	CAIR I	2	9
Annual $PM_{2.5}$	2012 remedy	1	2
	CAIR I	1	1
8-hr ozone	2012 remedy	7	14
	CAIR I	8	18
		Number of Downwind Monitors	
NAAQS	**Scenario**	**Nonattainment**	**Maintenance**
24-hr $PM_{2.5}$	2014 remedy	1	1
	CAIR II	1	2
Annual $PM_{2.5}$	2014 remedy	0	1
	CAIR II	0	1

In almost every comparison, there are very few differences in the numbers of nonattainment and maintenance sites projected to remain following implementation of the Proposed Transport Rule and following implementation of CAIR. This indicates that no meaningful additional benefit is achieved by the emission reductions required under the Proposed Transport Rule beyond those required under CAIR, despite the increased cost and constraints that come along with the Proposed Transport Rule.

Additionally, in developing the Proposed Transport Rule, EPA assessed the effects of NOx emission reductions first, before considering the effects of SO_2 emission reductions, despite EPA's acknowledgement that "SO_2 reductions are generally more effective than NOx reductions at reducing $PM_{2.5}$." 75 Fed. Reg. at 45281/1-2. This artificially inflates the projected contribution of NOx emissions to the formation of $PM_{2.5}$. As EPA has acknowledged, for example, the contribution of NOx emissions to $PM_{2.5}$ formation in southeastern states is considerably smaller than the contribution of SO_2 emissions to $PM_{2.5}$ formation. *See* 75 Fed. Reg. at 45237/1. In fact, it is minimal. *See* comments of Southern Company on the PTR (explaining, among other things, that particulate nitrate represents a very small fraction -- approximately five percent -- of $PM_{2.5}$ in southeastern states).[42] Had EPA taken a more logical approach and assessed SO_2 reductions first, it would have found that adding NOx reductions provides little additional improvement in key air quality indicators. Table VII-3 below, which was developed by Southern Company by replicating EPA's air quality assessment tool, illustrates the effect of assessing SO_2 reductions before NOx reductions.

[42] Southern Company's comments also explain, among other things, that although particulate nitrate can represent an important fraction of $PM_{2.5}$ during the winter in northern states, EPA should not have required annual NOx reductions in the PTR because EPA does not include consideration of ammonia emissions in the PTR. The formation of particulate nitrate is an inherently non-linear process, is strongly thermodynamically driven, and is strongly associated with available ammonia. Thus, by excluding ammonia from consideration, EPA cannot properly assess the role of NOx versus ammonia in particulate formation, especially using the linear assumptions in its air quality assessment tool.

Table VII-3			
24-hour $PM_{2.5}$ - 2014		**Number of Downwind Monitors**	
$/Ton SO_2	**$/Ton NOx**	**Nonattainment**	**Maintenance**
0	0	40	71
0	500	39	64
100	0	6	16
100	500	5	15
200	0	3	11
200	500	1	9
300	0	1	8
300	500	1	6
400	0	1	7
400	500	1	5
Annual $PM_{2.5}$ - 2014		**Number of Downwind Monitors**	
$/Ton SO_2	**$/Ton NOx**	**Nonattainment**	**Maintenance**
0	0	13	20
0	500	12	19
100	0	3	4
100	500	2	3
200	0	2	3
200	500	2	3
300	0	1	3
300	500	1	3
400	0	1	2
400	500	1	1

This indicates that for both the annual and 24-hour $PM_{2.5}$ NAAQS, the number of downwind nonattainment and maintenance monitors is driven primarily by reductions in SO_2 emissions. There are only very slight changes in the numbers of downwind nonattainment and maintenance monitors when SO_2 emissions are not reduced and NOx emissions are reduced using EGU NOx controls available at $500 per ton. By contrast, when SO_2 emissions are reduced using EGU SO_2 controls available at $100 per ton, there are significantly fewer downwind nonattainment or maintenance sites, and reducing NOx emissions using EGU NOx controls available at $500 per ton yields only a very slight difference. This same pattern holds true when SO_2 emissions are reduced using EGU SO_2 controls available at $200 per ton, $300 per ton, and $400 per ton --

although the additional incremental improvement even from the SO_2 reductions that are achieved at $300 and $400 per ton is minimal. In each case, the difference between reducing NOx emissions using EGU NOx controls available at $500 per ton and not reducing EGU NOx emissions at all is very slight if there is any difference at all.

The role of NOx in particulate matter formation is further complicated by recent research demonstrating that the production of biogenic secondary organic aerosol ("SOA") is heavily influenced by NOx levels.[43] Specifically, this research shows that biogenic SOA, particularly isoprene, is enhanced with lower NOx levels due to changes in the fate of peroxy radicals. Air quality models at present do not include this newly discovered chemistry. In addition, the proper simulation of ammonium nitrate and other nitrate aerosol (*e.g.*, organic nitrates) has confounded air quality scientists for many years. Thus, the representation of the impacts of NOx emission changes in particulate matter levels in these models is incomplete, particularly when attempting to simulate relatively small signals such as interstate contributions to ambient particulate matter concentrations.

[43] *See, e.g.*, Chan, M. N. et al. (2010), Characterization and quantification of isoprene-derived epoxydiols in ambient aerosol in the southeastern United States, Environmental Science & Technology, 44(12), 4590-6, doi:10.1021/es100596b; Surratt, J. D., A. W. Chan, N. C. Eddingsaas, M. Chan, C. L. Loza, A. J. Kwan, S. P. Hersey, R. C. Flagan, P. O. Wennberg, and J. H. Seinfeld (2010), Reactive intermediates revealed in secondary organic aerosol formation from isoprene, Proceedings of the National Academy of Sciences of the United States of America, 107(15), 6640-5, doi:10.1073/pnas.0911114107; Paulot, F., J. D. Crounse, H. G. Kjaergaard, A. Kürten, J. M. St Clair, J. H. Seinfeld, and P. O. Wennberg (2009), Unexpected epoxide formation in the gas-phase photooxidation of isoprene, Science (New York, N.Y.), 325(5941), 730-3, doi:10.1126/science.1172910; Paulot, F. (2009), Unexpected Epoxide Formation in the, Science, 730, doi:10.1126/science.1172910; Hallquist, M. et al. (2009), The formation, properties and impact of secondary organic aerosol: current and emerging issues, Atmospheric Chemistry and Physics Discussions, 9(1), 3555-3762, doi:10.5194/acpd-9-3555-2009; Ng, N. L. et al. (2007), Effect of NOx level on secondary organic aerosol (SOA) formation from the photooxidation of terpenes, Atmospheric Chemistry and Physics Discussions, 7(4), 10131-10177, doi:10.5194/acpd-7-10131-2007; Surratt, J. D. et al. (2006), Chemical composition of secondary organic aerosol formed from the photooxidation of isoprene, The journal of physical chemistry. A, 110(31), 9665-90, doi:10.1021/jp061734m.

EPA should reevaluate the marginal air quality benefits that are projected from incremental increases in cost for EGU SO_2 controls above low levels, such as $300 to $400 per ton, and should reconsider the SO_2 cost breakpoint in that light. Additionally, because of the very minimal benefit that is achieved from reducing EGU NOx emissions in addition to SO_2 emissions, as well as the other issues discussed above, EPA should consider removing annual NOx reduction requirements from the proposed rule.

G. EPA Has Failed To Explain Why It Did Not Use 2008 Heat Input Data in Calculating SO_2 Emission Budgets.

EPA proposes to set state emission budgets for annual and ozone season NOx and for SO_2 based on the quantity of emissions that remain after elimination of significant contribution to nonattainment and interference with maintenance, but before accounting for variability. 75 Fed. Reg. at 45290/2. In its TSD addressing state budgets, EPA explains that it calculated 2012 state budgets using a combination of emissions and heat input data reported to EPA as of 2009[44] and IPM projections for 2012, each adjusted to reflect emissions control equipment projected by EPA to be in place by 2012.[45] *See* State Budgets TSD at 3, 5.

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[44] According to EPA, it used the most recent non-null first, second, third, and fourth quarter emissions and heat input data between the first quarter of 2007 and the third quarter of 2009. Ozone season NOx emissions budgets were based on the most recent ozone season data reported between 2007 and 2009. EPA, "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD, at 5 (July 2010), *available at* http://www.epa.gov/airquality/transport/pdfs/TSD_StateBudgets_July152010.pdf ("State Budgets TSD").

[45] Many of the assumptions that EPA made in projecting the emissions control equipment that would be in place at individual units by 2012 are incorrect. *See* section VIII.A *infra* for a discussion of this issue and examples. EPA representatives have requested that, to the extent that EPA's projections are inaccurate, electric generating companies submit comments correcting them and explaining why they are inaccurate. Individual UARG members are submitting comments correcting EPA's projections to the extent that they contain inaccurate information regarding their units. However, to the extent that some companies fail to correct inaccurate

In that TSD, EPA notes that in creating the state budgets for annual and ozone season NOx, it "rebased" annual and ozone season NOx emissions for units reporting emission data to EPA by using 2008 rather than 2009 heat input. *Id.* at 9. According to EPA, this adjustment was made "to account for unusually low utilization [or heat input] in 2009." *Id.* During a conference call on August 30, 2010, however, EPA staff offered UARG members a different explanation for this adjustment. EPA staff indicated that the reason EPA used 2008 data was that the IPM projection of how sources would operate their NOx controls in 2012 did not align well with the 2009 data but aligned more closely with the 2008 data.

Whatever the reason or reasons EPA used 2008 instead of 2009 heat input data for NOx, EPA did not make a similar adjustment for unit-reported SO_2 emissions. EPA does not provide any explanation for this differential treatment of the issue as between the two pollutants. EPA does, however, state repeatedly in the preamble that it developed the state budgets based on projected emissions "in an average year." *See, e.g.*, 75 Fed. Reg. at 45214/2 ("A state's emissions budget is the quantity of emissions that would remain after elimination of the part of significant contribution and interference with maintenance the EPA has identified in an average year"); *id.* at 45271/2 (A state's budget "represent[s] the remaining emissions for the state in an average year"); *id.* at 45292/1 ("EPA has . . . developed state budgets based on its projections of state emissions in an average year"). Both the explanation in the TSD and the explanation

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projections regarding their units and the 2012 state budgets remain inadequate, all companies in the program will be affected. Requesting comments to correct a vast array of assumptions, especially in the short period of time that EPA has allowed for public comment on this lengthy and complicated proposed rule, is not adequate. EPA should have issued an advance notice of proposed rulemaking and communicated with electric generating companies to ensure that the information that it was using to develop the proposal was accurate. Having not done that, and seeing that these vital assumptions are inaccurate in many cases, EPA must either withdraw the proposed rule and begin the rulemaking anew or issue a comprehensive supplemental notice of proposed rulemaking for public comment.

offered on the August 30 conference call seem to indicate that EPA believes that 2009 heat input was not heat input for an average year, at least for NOx budget purposes.[46] It is far from apparent why, if 2009 heat input was not average for -- and therefore was not used for -- NOx budget purposes, there would be any basis to use it for SO_2 budget purposes. Before it proceeds further with this rulemaking, therefore, EPA will need to clarify and provide an adequate explanation for its decision to use 2009 heat input data for SO_2. Prior to taking any final action to promulgate a rule, EPA should provide an opportunity for the public to comment on this important matter in light of an adequate explanation by the Agency.

VIII. EPA's Use of Inaccurate Inputs and Assumptions for -- and Unrealistic Outputs from -- EPA's Use of the Integrated Planning Model Makes the Proposed Transport Rule Inadequate for Public Comment.

The principal analytical tool on which EPA relied in developing the unit allowance allocations and statewide emission budgets in the Proposed Transport Rule is IPM. The results of EPA's numerous IPM runs provide the Agency with substantially all of the key data points to make its decisions on these critical elements of the PTR. As EPA explains in its TSD discussing its use of IPM, that model[47]

> provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting electricity demand, environmental, transmission, dispatch, and reliability constraints. IPM can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon dioxide (CO_2) and mercury (Hg)

[46] UARG believes that EPA should have based state budgets on heat input in a higher-than-average year, at least for the first several years of the program, to allow for flexibility in the event that demand in those years requires higher-than-average generation.

[47] EPA's NODA, published on September 1, 2010, states, among other things, that the Agency had placed in the docket an updated version of IPM (v.4.10), along with a number of other documents and IPM runs. The present comments on the PTR are limited to IPM v.3.02 as used in developing the PTR and the runs produced by that version of the model. In its comments on the NODA, UARG will address issues concerning v.4.10 of IPM.

from the electrical power sector and is used extensively by EPA to support regulatory activities.[48]

A fundamental limitation on the accuracy of any model is the quality of the inputs to the model. Among the most critical inputs to IPM are the emission inventory and unit-level characteristics and operating parameters. The primary source for unit-level emission information for IPM is the NEEDS database. The NEEDS database is fraught with significant errors, as illustrated in section VIII.A below. In addition, other inputs can be used for, and limitations placed on, IPM analyses to reflect particular, unique situations such as state-specific regulations of EGU emissions and NSR settlements that may limit those emissions. IPM refers to such inputs as "constraints." Section VIII.A below also details various errors in the "constraints" EPA placed on the IPM model runs.

Moreover, the outputs from EPA's IPM runs, when compared to actual unit-specific data and individual companies' plans, are inaccurate and unrealistic. The validity of a given set of outputs from an application of any modeling tool is brought into question when the modeled results do not reflect real-world conditions.[49] The second subsection below provides specific examples of inconsistencies between EPA's IPM projections and individual companies' plans for their units. The following examples are an illustrative, but by no means an exhaustive, list of problems in the NEEDS database and EPA's application of IPM to support the Proposed Transport Rule.

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[48] Updates to EPA Base Case v3.02 EISA Using the Integrated Planning Model, Docket ID No. EPA-HQ-OAR-2009-0491, at 3 (June 17, 2010), *available at* http://www.epa.gov/airquality/transport/tech.html.

[49] Another problem with the outputs from IPM results from the fact that IPM does not perform a probabilistic analysis. IPM outputs give the illusion that they are precise even though they are not. It would be more realistic for EPA to consider a range of projected data than to treat a single data point from IPM as a precise data point for purposes of calculating budgets and allowance allocations.

A. Many of the IPM Inputs for Individual Units Are Inaccurate.

Errors in the NEEDS database identified by UARG members generally fall into three categories: (1) emission controls that were assumed to exist currently but do not; (2) overestimated emission control efficiencies of existing control equipment; and (3) failure to account for emission controls or limits that do exist.

Examples of pollution controls that were assumed to exist but do not include the following:

- NEEDS reports that PM scrubbers are already installed and operational at the Harrison power plant in West Virginia. PM scrubbers do not exist at that plant.
- NEEDS reports that selective non-catalytic reduction ("SNCR") is already installed and operational at two units at the Armstrong power plant in West Virginia. SNCR does not exist at these two units.
- NEEDS reports that FGD is to be installed at unit 4 at the Scherer power plant in Georgia in 2011. The current target installation date is August 2012.
- NEEDS reports that SNCR is to be installed at units 4 and 5 at the Jack Watson power plant and units 1 and 2 at the Daniel power plant in Mississippi. No SNCRs exist or are planned for these units.
- NEEDS reports that a wet scrubber will be installed at unit 3 at the Brayton Point power plant in Massachusetts by 2012. Under a state-approved Emission Control Plan, a dry scrubber will be installed and will commence operation in 2014.
- NEEDS data indicate that an SCR on unit 3 at the E.W. Brown power plant in Kentucky is to be installed by the beginning of 2012. An SCR is under construction at that unit but will not be completed until the end of 2012.
- NEEDS data indicate that an SCR exists on unit 2 at the Ghent power plant in Kentucky as of 2009. SCR neither exists nor is planned for this unit.

Examples of overestimation by NEEDS of removal efficiency of controls that currently exist:

- NEEDS reports the FGD control efficiency at the Mitchell power plant in West Virginia at 99.9% -- an impossible figure to achieve. The actual average removal efficiency is 97%.

- NEEDS reports the FGD control efficiency at the Pleasants power plant in West Virginia at 97%. The actual average removal efficiency is 95%.

Examples of emission controls that do exist but were not included:

- NEEDS fails to account for FGD systems at the Harrison power plant in West Virginia.

- NEEDS fails to account for FGD systems at three units at the Hatfield's Ferry power plant in West Virginia.

- NEEDS fails to account for FGD systems at two units at the Fort Martin power plant in West Virginia.

- NEEDS fails to account for a state SO_2 emission limitation on the Cumberland power plant in Tennessee of 0.5 lb/mmBtu and instead reports SO_2 emissions at that plant at a rate of 5.0 lb/MMBtu.

In addition, errors in IPM constraints and inputs appear to be related to inaccurate interpretation of state regulations and NSR settlements, and there are other errors as well. Examples include:

- IPM assumes (in the 2014 base case) that units 1 and 2 at the Harllee Branch power plant in Georgia will each have an FGD and SCR in place by 2014 (presumably, January 1, 2014). The Georgia Multipollutant Rule instead requires that these be in place by December 31, 2014.

- IPM assumes (in the 2014 base case) that unit 4 at the Harllee Branch power plant in Georgia will have an FGD and SCR in place by 2014 (presumably, January 1, 2014). The Georgia Multipollutant Rule instead requires that these be in place by June 1, 2014.

- IPM assumes (in the 2014 base case) that units 6 and 7 at the Yates power plant in Georgia will each have an FGD and SCR in place by 2014 (presumably, January 1, 2014). The Georgia Multipollutant Rule instead requires that these be in place by June 1, 2015.

- IPM assumes (in the 2014 base case) that unit 1 at the Scherer power plant in Georgia will have an FGD and SCR in place by 2014 (presumably, January 1, 2014). The Georgia Multipollutant Rule instead requires that these be in place by December 31, 2014.

- IPM assumes that FGD retrofits at the Kyger Creek and Clifty Creek power plants in Ohio are complete and operational. These retrofits are not complete, and construction is currently suspended.
- IPM assumes that one of the primary units of the Cumberland power plant in Tennessee has an SO_2 emission rate of 5.0 lbs/mmBtu. The unit is currently regulated by and is complying with a state regulation that limits its SO_2 emissions to 0.5 lbs/mmBtu.
- IPM assumes that the Maryland Healthy Air Act allows for limited interstate trading and/or intrastate trading, depending on the proposed remedy, and IPM appears to treat similar sources in Maryland very differently, judging from the IPM-based allowance allocations for units. The Maryland Healthy Air Act in fact only allows for intra-company trading of allowances and the unit-specific allowances established in the Maryland Healthy Air Act appear to have been ignored.

In addition to the NEEDS and IPM input errors, it appears EPA made downward adjustments to NOx emission rates in IPM that are unwarranted, unreasonable, and inaccurately described in the State Budgets TSD. The State Budgets TSD indicates that "NOx controls were assumed not to control beyond a floor of 0.06 lb/mmBTU."[50] The 0.06 lb/mmBTU rate would be more accurately described as a ceiling than a floor because of the adjustments EPA made to NOx emission rates. If a unit reported historical data that supported a NOx emission rate *lower* than 0.06 lb/mmBTU, EPA used that lower emission rate. Yet if a unit reported historical data that demonstrated a NOx emission rate *higher* than 0.06 lb/mmBTU, EPA -- apparently arbitrarily -- made a downward adjustment of that rate to 0.06 lb/mmBTU. Such downward adjustments are unfair and unwarranted. Incentives exist in most cases to emit at the lowest reasonably achievable NOx emission rate, and if a given unit reports NOx emissions at rates above 0.06 lbs/mmBTU, it is likely that that unit cannot physically and consistently operate at a lower rate. At a minimum, an across-the-board downward adjustment to 0.06 lb/mmBtu, without

[50] State Budgets TSD at 6.

consideration of case-by-case factors, cannot be justified. Under EPA's proposed approach, where an existing unit cannot in fact meet the 0.06 lb/mmBTU rate, that unit may well be forced to upgrade its pollution control device or acquire allowances. EPA did not anticipate either of these options in the PTR and does not seem to have accounted for the costs associated with these options in the PTR. EPA should abandon its approach of making across-the-board downward adjustments to 0.06 lb/mmBTU and should instead use historical reported emission rates on a unit-by-unit basis.

B. EPA's IPM Outcomes Do Not Reflect Actual Source Operations.

UARG members have found many inconsistencies between EPA's IPM-projected operating scenarios for units in 2012 and 2014 and their own plans and projections. While EPA may argue that IPM accounts for the impact of the proposed controls and that generators are not capable of appreciating the influence of the proposed controls on their future operations, UARG members believe that their economic models, as well as their understanding of their operations, supply capabilities, and energy demand forecasts are more accurate than outputs of EPA's proprietary IPM. IPM was not designed for this level of specificity -- it is a regional-scale model. IPM often does not reflect real-world operations with respect to a number of key factors, including unit availability. Generators have years of experience with a greater level of specificity that allows them to understand the real-world constraints and demands on individual units and to better predict which units will run, how often they will run, and how long they will continue to run.

The inaccurate IPM projections fall into four categories: (1) inaccurate assumptions of emission controls; (2) inaccurate estimates of emission control efficiencies; (3) inaccurate assumptions of early retirement of particular units; and (4) inaccurate assumptions regarding fuel switching at particular units.

Examples of inaccurate assumptions of emission controls include the following:

- IPM projects FGD installations at the Armstrong power plant in Pennsylvania by 2014. No such installations are planned by the company.

- IPM projects FGD installation at the Willow Island power plant in West Virginia by 2014. No such installation is planned by the company.

- IPM projects SCR installation at unit 2 at the J.H. Campbell power plant in Michigan by 2012. No such installation is planned by the company.

- IPM projects installation and operation of LNBs with overfire air -- based on the listed emission rate -- at the J. R. Whiting power plant (units 1-3) in Michigan. The owner of the units does not believe such controls are viable options at these units due to operational and configuration constraints.

- IPM projects FGD installation and operation at unit 2 at the Muskingum River power plant in Ohio by 2011. Although a preliminary engineering study was conducted for unit 2, there is no ongoing construction and it would take at least three years to permit and build an FGD even if construction began immediately.

- IPM has not allocated NOx emission allowances to units 1 and 2 at the Salem Harbor power plant even through the IPM model for the 2012 base case predicts that these units will operate. This appears to be the result of erroneous adjustments made to projected IPM emissions to account for annual operation of each unit's SNCR. No adjustment was necessary. Actual emissions already represent annual operation of SNCR -- both SNCRs have been operating on a year-round basis since October 2005 to comply with a station-wide NOx limit in accordance with a state Administrative Consent Order.

Examples of inaccurate estimates of emission control efficiencies include the following:

- IPM projects an annual 35% NOx removal efficiency for two units at the Fort Martin power plant in West Virginia and one unit at the Hatfield's Ferry power plant in Pennsylvania. In fact, however, these units have only single-point injection controls capable of roughly 10% to 15% removal efficiency.

- IPM projects annual NOx emission rates at the Harrison power plant and the Pleasants power plant in West Virginia from SCR as low as 0.04 to 0.05 lb/mmBtu. Such low rates were periodically achievable when the SCR was initially installed, but representative operation of the controls demonstrates that such rates are not sustainable on a long-term basis and as the effectiveness of the SCR reduces as the catalyst ages.

Examples of inaccurate assumptions of early retirement of particular units include the following:

- IPM projects early retirement of two units at the Rivesville power plant and one unit at the Willow Island power plant in West Virginia by 2014. No retirements by 2014 are planned by the company.

- IPM projects early retirement -- by 2014 -- of units 1 and 2 at the McManus power plant in Georgia, and of units 1 and 3 at the Watson power plant, and units 1 and 2 at the Sweatt power plant, both in Mississippi. There are no plans by the company to retire these units by 2014.

- IPM projects early retirement of nine units in Michigan (B. C. Cobb units 1-3; D. E. Karn units 3 and 4; and Thetford units 1-4). There are no plans by the company to retire these units by 2014.

Examples of inaccurate assumptions regarding fuel switching for particular units include the following:

- IPM projects fuel switching from coal to natural gas for three units at the Albright power plant in West Virginia and for two units at the R. Paul Smith power plant in Maryland. These fuel switches are not planned by the company.

- IPM projects fuel switching from coal to natural gas for the McManus power plant in Georgia. This fuel switching is not planned by the company.

- IPM projects fuel switching from higher sulfur coal to 100% Powder River Basin coal by 2012 at units 4 and 5 at the B.C. Cobb power plant and units 1-3 at the J. R. Whiting power plant in Michigan. Such a fuel switch is not feasible due to the limited timeframe and outstanding coal, rail-line, and rail-car contracts.

- IPM projects fuel switching to low-sulfur Eastern coals at units 1-4 of the Muskingum River power plant in Ohio. These units are wet bottom/cyclone-fired boilers that, historically, do not tolerate such coal because of its high ash-fusion temperatures.

In addition to these facility-specific errors, EPA's application of IPM reveals certain systemic errors in the analysis supporting the PTR. Perhaps most notable is IPM's treatment of dual-fuel units, *i.e.*, units capable of burning either natural gas or oil. Of the 493 dual-fuel units in the NEEDS database, IPM predicted in the 2014 limited trading control strategy that 34 units would burn oil as the primary fuel. EPA proposes to allocate any SO_2 allowances to only 8 of those 34 units. This result ignores the reality that many dual-fuel units do regularly burn oil for some part of the year, whether due to natural gas supply limitations,[51] price factors, or facility-specific constraints. The mere fact that the IPM analysis may project that it will be more economical to run these units on natural gas than on oil does not mean that the real-world factors that lead to combustion of oil at these units simply disappear.

IPM projection errors of this sort appear to be a function of inherent limitations of IPM and/or EPA's limited knowledge of certain local factors. IPM is a least-cost economic model designed to predict operations at a fairly broad regional level. In many instances, EPA lacks sufficient information about local issues such as transmission constraints, capacity commitments, fuel-contract commitments, and other cost-related considerations that have not been input to the IPM model. EPA's insufficient information, coupled with the limitations of the regional IPM model, result, for example, in inaccurate projections for oil-fired units and dual-fuel units. When IPM predicts natural gas is less expensive than oil or that burning oil at an oil-fired unit is for some reason not "economical" within the terms of IPM's protocol, no SO_2 emissions are projected from -- and thus no SO_2 allowances are allotted to -- that unit.

EPA must recognize the limitations of IPM and must consider local issues and allow UARG members, other generators, and other members of the public to comment on EPA's adjustments to address those issues. For example, it should be self-evident that particular units

[51] Natural gas markets and suppliers essentially "close" at 6 p.m. each day. Individual generating companies bargain before closing each day for their guaranteed supply of gas for the following day. If there is not enough gas in the pipeline to meet demand the following day, units may have to run on oil to meet demand. Additionally, many natural gas pipelines offer only "interruptible" service, in which gas supplies may be reduced or temporarily curtailed to meet higher-priority customers. When service is interrupted, units are forced to burn oil to meet demand. Many dual-fuel units are peaking units and may need to burn incremental volumes of oil in peak-demand periods.

that have burned oil in the past, and that continue to burn oil, can be expected to burn oil in the future and should receive allowance allocations; the presumption should be in such cases that allowance allocations to those units are appropriate in the absence of compelling reasons to the contrary. At a minimum, EPA should not blindly insist that IPM's projections for these types of units are accurate and should instead make adjustments to the allocation determinations for these types of units, based on comments of companies with interests in those units.

Another systemic error involves the heat input rates listed in the "BADetaileddata.xls" spreadsheet associated with the proposed direct control alternative remedy. Heat input is overstated by a factor of 10 in this spreadsheet. Because of the absolute tonnage cap in the direct control case, these artificially high heat input levels are essentially meaningless in this context. Nonetheless, these types of errors draw into further question the accuracy and validity of the NEEDS database and IPM modeling runs.

Accordingly, EPA should correct the errors in the NEEDS database and correct the erroneous and inaccurate IPM inputs and then rerun the critical IPM model runs, to the extent EPA continues to use IPM modeling as a basis to develop state budgets. Given the serious limitations in IPM's capabilities as discussed above, EPA should develop for public review and comment alternative methods of calculating unit allowance allocations (for example, alternative methods that use appropriate measurements of units' historical heat input, as EPA did in the NOx SIP Call rule and CAIR). EPA should then publish revised proposed budgets and allocations for public review and comment. However, any proposed allocations should at most be "model" allocations for consideration by the states; for the reasons discussed elsewhere in these comments, EPA has an obligation to allow each state to make -- and to give each state adequate *time* to make -- any emission control decisions for sources within the state and to incorporate those decisions in SIPs.

IX. Certain EPA Assumptions and Determinations Do Not Account Adequately for the Interaction Between the Proposed Rule and Other CAA Programs.

A. Contrary to EPA's Assumption, Permitting Requirements Cannot Be Expected To Be Met in Time To Satisfy the Proposed Transport Rule's Compliance Schedule.

EPA asserts, based on an analysis[52] that it conducted following the D.C. Circuit's decision in *New York v. EPA*, which vacated the PCP exclusion in EPA's NSR regulations, that NSR permitting requirements "[will] not significantly impact the construction of controls that are installed to comply with the proposed transport rule." 75 Fed. Reg. at 45343/3. EPA vastly underestimates the complexity of this issue in the proposed rule. As explained above in section V.A.2, although the operation of SCR and FGD units will reduce emissions of NOx and SO_2, in many cases operation of these controls may be thought to result in an increase in emissions of other pollutants by more than insignificant amounts. Contrary to the assumptions that EPA made in its 2005 analysis, experience has shown that NSR permitting requirements will significantly impact the construction of controls. *See* section V.A.2 *supra* (noting that NSR permitting can be expected to add many months to over a year to the process of adding FGD or SCR units).

EPA must take a realistic view, based on real-world, practical experience, regarding the implications of NSR permitting requirements for the installation of controls required under the proposed rule, taking into account the effect that the court's vacatur of the PCP exclusion has had on NSR permitting. Such a realistic view would reveal that the impact of NSR permitting

[52] *See* "Impact on CAIR Analyses of D.C. Circuit Decision in *New York v. EPA*" (Dec. 2005), *available at* http://epa.gov/cair/pdfs/0053-2263.pdf.

requirements on the construction of controls required under the proposed rule is likely to be significant.

B. EPA Should Provide Justification for Its Unsupported Assertion that It Is "Very Unlikely" that Pollution Control Projects Would Cause GHG Emission Increases in Excess of the PSD Emission Thresholds in the Agency's June 2010 GHG Tailoring Rule.

According to EPA, the analysis referred to above in section IX.A, conducted following the D.C. Circuit's decision in *New York v. EPA*, indicated that the court's decision on the PSP exclusion issue would not affect the assumptions underlying EPA's determination that CAIR was cost-effective and feasible. EPA states simply that it believes that the same is true for the Proposed Transport Rule. 75 Fed. Reg. at 45343/3.

Although EPA's CAIR analysis did not address greenhouse gases ("GHGs") because they were not regulated CAA pollutants at that time, EPA concludes in the Proposed Transport Rule that it is "very unlikely" that pollution control projects would cause GHG emission increases in excess of the NSR emission thresholds in EPA's June 2010 GHG Tailoring Rule. 75 Fed. Reg. at 45344/1. At least in part for this reason, EPA concludes that NSR impacts are not likely with respect to emission control projects required to satisfy the Proposed Transport Rule. 75 Fed. Reg. at 45344/1. EPA provides no justification for this assumption. If EPA is wrong, the implications for NSR permitting -- and for the necessary compliance schedule for implementation of any rule such as the Proposed Transport Rule -- will be substantial. EPA must, at a minimum, provide an analysis and explanation to support its assertion and make that analysis and explanation available for public comment before it proceeds further with this rulemaking.

X. EPA Should Amend the Proposed Transport Rule To Allow for Increased Flexibility in Compliance and Allowance Trading.

A. The Variability Limits and Assurance Provisions Proposed by EPA Are Unduly Stringent and Should Be Adjusted.

1. Variability Limits.

EPA's explanation in the preamble to the proposed rule, and in the TSD on Power Sector Variability[53] ("Variability TSD"), of its method for selecting the 10 percent uniform emission variability value is less than clear. At a minimum, it does not appear that EPA's analysis precludes a conclusion that a higher uniform percentage is justified. EPA should carefully consider the basis for adopting a higher percentage.

The Variability TSD describes an analysis that EPA performed, using its air quality assessment tool, to evaluate the effect of variability in emissions in upwind states on air quality in downwind states. According to this TSD, EPA performed this analysis using two different approaches, each of which examined the effects of variations in SO_2 emissions from upwind states on 24-hour $PM_{2.5}$ concentrations at downwind nonattainment and maintenance monitors. Variability TSD at 43. In the first approach -- intended to replicate "typical" variation -- EPA projected that SO_2 emissions in each upwind state in the proposed control region would vary randomly. *Id.* at 44. In the second approach -- intended to replicate "worst case" variation -- EPA projected, on a monitor-by monitor basis, that SO_2 emissions in the upwind states with the largest air quality impacts per ton on the downwind monitor increased to the maximum amount (up to each state's one-year variability limit) and that SO_2 emissions in all of the other upwind states decreased to compensate for the increased emissions from the high-impact states (so that the regionwide emissions in the proposed control region equaled the sum of all state budgets).

[53] EPA, "Power Sector Variability" TSD (July 2010), *available at* http://www.epa.gov/airquality/transport/tech.html.

Id. at 47. EPA reported that "[f]or both approaches, the effects of the inherent variation in emissions on daily $PM_{2.5}$ concentrations were estimated to be small." *Id.* at 44; *see also id.* at 46 (reporting that the results of the analysis using the first ("typical" variation) approach indicated that "the combined downwind air quality impacts were essentially negligible"), 47 (reporting that the results of the analysis using the second ("worst case" variation) approach indicated that "the resulting increases in air quality are small relative to other factors (*i.e.*, weather)").

UARG commends EPA for conducting this analysis and agrees in broad terms that this analysis demonstrates that interstate trading can play a valuable role in reducing emissions without decreasing downwind air quality. However, it is not apparent, and EPA does not explain, why it chose to perform this analysis using only a variability limit of 10 percent of the state budgets. EPA should perform the analysis using higher variability limits, in the range of at least 20 to 30 percent of each state's budget. If these analyses also indicate that the impact of upwind emissions variability on downwind air quality remains small, higher variability limits would be justified.

UARG strongly urges EPA to consider increasing the variability limit. A higher variability limit would encourage emission trading and increased emission reductions at sources where they are most cost-effective to achieve (thus lowering the overall cost of compliance with the program), while still ensuring that substantial emission control levels are maintained within each state. In fact, an analysis conducted by Southern Company and described in its comments on the Proposed Transport Rule indicates that even unrestricted interstate emission trading could yield air quality that is substantially the same as if trading were not allowed under the proposal.[54]

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[54] *See* Southern Company's comments on the PTR (describing the results of an analysis comparing state budgets under CAIR and under the PTR, which suggests that if unlimited

2. Assurance Provisions.

EPA requests comments on the proposed assurance provisions. 75 Fed. Reg. at 45314/2. UARG believes that the allowance surrender requirement associated with the assurance provisions should be *less* than one allowance per ton emitted, in addition to the standard allowance surrender. An additional allowance surrender requirement of one allowance per ton would be unnecessarily burdensome and overly punitive. EPA states in the proposed rule that it "believes the likelihood of triggering assurance provisions is low." *Id.* at 45314/1. Indeed, the example that EPA provides of a circumstance that may lead to emissions "approaching the variability limit" -- "an extended nuclear unit outage that causes a company to run its fossil units harder to meet demand" -- indicates that EPA anticipates the assurance provisions would likely be triggered only in unusual conditions and for a temporary period, due to forces largely beyond the unit owner's control. *Id.* Any allowance surrender in addition to the standard allowance surrender of one allowance per ton -- perhaps, for example, an additional ½ allowance (rather than the additional one allowance) on top of the standard one-allowance surrender requirement -- would provide an adequate incentive for unit owners to avoid exceeding their share of the state budget with variability limits.

Additionally, for similar reasons, UARG strongly believes that such an exceedance should not be considered a violation of the CAA, subject to discretionary penalties. *See* 75 Fed. Reg. at 45314/2 (requesting comment on whether such exceedances should be considered a violation of the CAA and be subject to discretionary penalties). As explained above, any

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interstate trading were permitted under the PTR, air quality indicators could be very similar to the air quality indicators if no interstate trading were permitted).

additional allowance surrender requirement would provide sufficient incentive to avoid triggering the assurance provisions.[55]

B. Units Should Be Permitted To Borrow Allowances From Future Year Allowance Accounts, at Least on a Limited Basis.

EPA should allow units to "borrow" allowances from future-year accounts for use in compliance, at least on a limited basis. This would allow for increased flexibility, which will be particularly important in the early years of the program, especially if EPA promulgates a final rule that includes the ambitious compliance schedule that it proposes. *See* sections III and V *supra* for UARG's comments on the compliance schedule. However, this feature would still result in units receiving and using a finite number of allowances over the years and, thus, produce no overall increase in emissions.[56]

C. EPA Should Not Establish Any Government-Run Allowance Auctions.

Although UARG does not support EPA's Intrastate Trading Remedy Option, if EPA promulgates a final rule based on this option, EPA should not provide for government-run allowance auctions. As noted above in section II.C, governmental auctioning of allowances is contrary to the principle that regulated sources are permitted to emit up to their allowance allocation levels without bearing any obligation to pay for the right to emit up to those levels.

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[55] UARG does not believe that EPA's proposed discretionary penalties for excess emissions, 75 Fed. Reg. at 45314/3, are appropriate. Those penalties could easily amount to millions of dollars for an inadvertent exceedance of allowance levels by even a few tons in one year. EPA should at a minimum clarify that in the allowance trading program that EPA proposes, an exceedance of one ton of emissions will be treated as a single violation over one year or ozone season, as the case may be, rather than as a separate violation for each day in that year or ozone season. This change is particularly appropriate because any exceedances of allowance levels under the Transport Rule are almost certain to be inadvertent.

[56] One potential approach that EPA could consider in developing a "borrowing" program could involve a requirement that borrowers pay a reasonable amount of "interest" in future years in the form of additional allowance requirements, reflecting the amounts borrowed and the term of the "loan."

EPA explains in the Proposed Transport Rule that revenues from the allowance auctions described in the section on the Intrastate Trading Remedy Option would be deposited into the U.S. Treasury. 75 Fed. Reg. at 45327/2. The effect of such auctions, besides providing revenue to the federal government, would be to force affected sources to pay not only for emissions that exceed their emission allowance allocation limits (by purchasing allowances on the market) but also for the right to emit *below* those limits. No legal basis exists for charging sources for emissions below their allocation levels, and providing revenue to the U.S. Treasury is not a legitimate purpose of section 110(a)(2)(D)(i)(I) of the CAA. Moreover, as discussed above, EPA has not shown that any legal authority exists for EPA to auction allowances and thereby impose what amounts to a tax, with tax revenue flowing to the federal government.

In short, EPA should not promulgate a rule based on the intrastate trading option, but if it does, it should remove government-run allowance auctions from the design of that option. Instead, to the extent EPA concludes it is necessary to make additional allowances available under that option to energy producers with limited market share, EPA should provide for adjustments in the distribution of allowance allocations but without auctioning the allowances.

XI. Requirements for Electronic Reporting of Quarterly Reports

UARG has several objections to EPA's proposed requirements for quarterly reporting.

A. Electronic Reporting Format

First, UARG objects to EPA's proposed requirement that source owners and operators submit electronic quarterly reports "in the format prescribed by the Administrator." Proposed §§ 97.434(d)(1), 97.534(d)(2)(ii), 97.634(d)(1), and 97.734(d)(1). In the preamble, EPA describes this requirement as identical to that contained in 40 C.F.R. Part 75 ("Part 75"), which establishes monitoring, recordkeeping, and reporting requirements for the Acid Rain Program (ARP), NO_x Budget Program, and CAIR. 75 Fed. Reg. at 45325/2 - 45326/1. UARG is surprised that EPA did not acknowledge in that discussion that the Part 75 requirement was challenged judicially (by UARG), and that the litigation has not yet been resolved. UARG objects to this requirement for the same reasons it objects to the requirement under Part 75.

Under Part 75, reports must be submitted in a "format to be specified by the Administrator, including electronic submission of data" by "direct computer-to-computer electronic transfer via EPA-provided software, unless otherwise approved by the Administrator." 40 C.F.R. § 75.64(d) and (f). UARG challenged these provisions in part based on (1) concerns regarding the nature and content of EPA's format, which the Agency has changed with some frequency, (2) the EPA-provided software's failure to ensure compliance with basic requirements of the ARP and the Cross-Media Electronic Reporting Rule ("CROMERR"),[57] and (3) the lack of appropriate procedures for submitting reports when a source is unable to gain access to EPA's computer with the EPA-provided software, or connect to the internet in a secure environment.[58] *See Appalachian Power Co., et al., v. EPA*, No. 99-1302 (D.C. Cir., filed July 23, 1999); *Utility Air Regulatory Group v. EPA*, No. 02-1254 (D.C. Cir., filed August 12, 2002). These cases have been held in abeyance pending discussions aimed at resolving these concerns.

As UARG explained in the Part 75 rulemaking, if EPA makes the format itself (as opposed to the requirement to submit the information) a regulatory requirement, EPA has an

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[57] For example, EPA's software does not provide a record of "submission" that is consistent with the requirements of §§ 75.62(a), 75.63(a), 75.64(a) and the definition of "submit or serve" under § 72.2. EPA also has provided no documentation to assure that its software satisfies the requirements of CROMERR at 40 C.F.R. Part 3.10.

[58] Currently, when a source cannot gain access to EPA's reporting system in time to meet a reporting deadline, EPA handles the issue by "allowing" the designated representative to submit the quarterly report by email. However, submission by email does not comply with the Agency's requirements for electronic reporting under CROMERR, which imposes source owner and operator liability for electronic reporting to an "undesignated" EPA electronic receiving system or without a valid electronic signature as defined in CROMERR. Email does not meet the electronic signature requirements of CROMERR.

obligation to subject that format to notice-and-comment rulemaking and review by the Office of Management and Budget ("OMB"). The EPA electronic reporting formats specified to date by the Administrator have been sufficiently complex and substantive that it is not appropriate to totally exempt them from rulemaking.[59] To the extent some flexibility is needed to make adjustments to the format, that flexibility can be provided by rule.

ARP sources have spent years and hundreds of thousands (if not millions) of dollars attempting to comply with these EPA-specified formats. The formats and related instructions for the ARP are hundreds, if not thousands, of pages in length with few or no citations to the underlying rule requirements. In some cases, the formats have included requirements to submit data that are not otherwise required to be reported under the rules. Each time EPA makes a revision to the format, software, or instructions, sources are required to respond. In some cases, this response requires modifications to the sources' own monitoring software at significant cost. Although EPA has responded to the electric generating industry's concerns by informally soliciting comment on the formats and instructions, committing to reducing the number of revisions to the format, and, in the recent redesign of the format, holding stakeholder meetings and providing contractor "technical support" during business hours, those efforts alone cannot cure what UARG believes is a legal defect in the rule. As implemented, EPA's electronic formats are substantive requirements that can impose significant burdens and impact sources' compliance status.

[59] Information on EPA's current format and submission requirements, called the Emissions Collection and Monitoring Plan System ("ECMPS"), is available at http://www.epa.gov/airmarkets/business/ecmps/index.html and at EPA's contractor's technical support website at http://ecmps.pqa.com.

B. Adjustments to Certified Information by the Administrator

Second, UARG objects to EPA's proposed language authorizing the Administrator to make adjustments to information personally certified by a designated representative ("DR") (or alternate DR, or "ADR"). Specifically, in proposed §§ 97.428, 97.528, 97.628, and 97.728, EPA proposes to allow the Administrator to perform independent audits concerning "any submission" and "make appropriate adjustments of the information in the submission." Under proposed §§ 97.414(a), 97.514(a), 97.614(a), and 97.714(a), DRs and ADRs are required to personally certify each submission as "true, accurate, and complete." At a minimum, EPA must make clear that any adjustments the Agency might make to information in a certified submission have not been certified by the DR or ADR. Moreover, UARG objects to the Agency's reservation to itself of the authority to unilaterally override a DR's or ADR's certification, without any procedure or criteria for establishing that the existing information is incorrect, or that the adjustment is in fact appropriate. EPA should remove these provisions.

C. Correction and Resubmission of Quarterly Reports

Proposed §§ 97.434(d)(4), 97.534(d)(7), 97.634(d)(4), and 97.734(d)(4) are new provisions that do not exist in Part 75 that would authorize EPA to (1) conduct reviews and audits of DRs' certified quarterly reports to determine whether they "meet[ ] the requirements of this subpart and part 75," (2) notify the DR of any "determination" that the report "fails to meet those requirements," and (3) specify in that notification "any corrections the Administrator believes are necessary to make through resubmission of the quarterly report." EPA proposes to require that the DR make the specified corrections, or provide "information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and Part 75." *Id.*[60] In the preamble, EPA characterizes this provision as codifying a process that is "implicit under, and has been in continuous use in, the Acid Rain, NO_X Budget, and CAIR trading programs." 75 Fed. Reg. at 45413/2-3.

UARG disagrees that this provision is consistent with current practice and objects to its inclusion in this rule. Each electronic report submitted under Part 75 is required to contain a certification by the DR or ADR that the information in the report is "true, accurate, and complete," and that the reported data were recorded in accordance with Part 75. 40 C.F.R. § 75.64(c). EPA proposes to include similar provisions in this rule. *See* proposed §§ 97.414(a), 97.434(e), 97.514(a), 97.534(e), 97.614(a), 97.634(e), 97.714(a), 97.734(e). Under the current Part 75 program, disagreements between EPA and DRs or ADRs (particularly following adoption of a new rule, rule revision, or reporting format change) about the accuracy of reports are not uncommon. Disagreements can arise for many reasons, including as a result of differences in rounding methodologies, differences in interpretation, EPA's use of the reporting "format" to collect information not otherwise required by rule to be submitted, and other errors or programming "bugs" in the electronic data quality assurance checks used by EPA to identify errors. Disagreements also occur as a result of the Agency's attempt to develop and impose new (and often unsupported) rule interpretations through the use of automated checks built into the EPA-provided software. Although DRs and ADRs generally will engage in discussions with EPA when EPA's report auditing software generates an "error" message with which the DR or ADR disagrees, nothing in the current rule or process requires the DR or ADR to "demonstrate"

[60] EPA also proposes to provide the Administrator complete discretion to decide what "a reasonable time period" is for resubmission. UARG objects to this as well. If EPA can design an appropriate resubmission requirement, EPA also should propose and solicit comment on what would constitute a "reasonable time period."

the correctness of its position in order to certify and submit a report or to avoid resubmission of a report.

To the extent the Administrator believes that a Part 75 report does not in fact meet the requirements of this subpart, EPA (not the DR or ADR) bears the burden of establishing that failure. EPA cannot use its reporting "format" and auditing techniques to establish a presumption of what constitutes compliance with Part 75, without subjecting its "reporting format" and software (including all of the audits contained in it) to rulemaking. EPA also cannot by rule shift the burden of proof with respect to establishing compliance to a source owner or operator's DR or ADR, who already has met the certification requirements of the rule, or compel a DR or ADR to certify a resubmitted report that the DR or ADR does not believe is correct. EPA should remove this provision, or restructure it to require resubmission only after the Administrator (not the source owner or operator) has established through an appropriate dispute resolution procedure that the report does not in fact meet the rule's requirement.[61]

XII. As a Matter of CAA Procedural Requirements, the Proposed Rule's Unfounded Assumptions, Errors, and Apparent Anomalies -- and EPA's Failure To Explain Adequately Critical Aspects of the Proposal and To Include in the Docket Information that Would Enable Replication of EPA's Process -- Make the Proposed Rule Inadequate for Public Comment.

Even apart from the fundamental legal deficiency in the Proposed Transport Rule -- *i.e.*, EPA's use of a "FIP-first" approach that improperly bypasses the SIP process, as described above -- and other flaws in EPA's proposal related to that deficiency, such as an improperly

[61] EPA recently proposed a report resubmission provision in proposed revisions to its rule for Mandatory Reporting of Greenhouse Gases at 40 C.F.R. Part 98, 75 Fed. Reg. 48744 (Aug. 11, 2010). *See* proposed § 98.3(h). This provision, which addresses resubmission in the context of "substantive errors," does not require or purport to allow EPA to unilaterally resolve questions of compliance with Part 75 in the context of an audit of a quarterly report. It merely requires the source owner or operator to resubmit a report in the context of his/her own determination that the report contained a "substantive error," or to submit information to the Administrator explaining why the DR or ADR does not believe the report contains a substantive error.

accelerated compliance schedule, other elements of the proposed rule make it inadequate as a notice of proposed rulemaking for public comment.

First, the unfounded assumptions, errors, and anomalies in the Proposed Transport Rule, as described in these comments, make EPA's proposal inadequate for public comment. For example, the assumptions regarding individual units described in section VIII above affect the state budgets and allocations of allowances. These problems are serious, and some of them appear to be due to causes that are not readily discernible from EPA's proposed rule and TSDs. Such problems might have been avoided had EPA issued an advance notice of proposed rulemaking as UARG requested in April 2009,[62] instead of developing the proposed rule without any meaningful opportunity for preliminary public review and input. Similarly, EPA's explanations of both its air quality assessment tool and the budgets and unit allocations are inadequate. Without additional explanation from EPA, it is impossible to replicate or validate EPA's significant contribution analysis and state budget and unit allocation calculations. *See* comments of Southern Company on the PTR (describing the lengths that it had to go to in order to try to replicate parts of EPA's analyses).

EPA must now revise the Proposed Transport Rule to remove these errors and anomalies, correct its ill-founded assumptions and judgments, and provide the critical missing explanations, and must either withdraw the proposed rule and begin the rulemaking anew or issue a comprehensive supplemental notice of proposed rulemaking for public comment.

[62] *See* Presentation to EPA on Behalf of UARG: CAIR Remand Issues: Principles that Should Guide EPA's Upcoming Rulemaking; The Perspective of the Utility Air Regulatory Group, at slide 2 (Apr. 17, 2009).

XIII. Conclusion.

For the foregoing reasons, and reasons to be discussed in UARG's comments on the NODA, although the Proposed Transport Rule does contain some commendable elements, the proposed rule overall is seriously flawed on legal, policy, and factual grounds. These flaws are so substantial that EPA should withdraw the proposed rule and replace it with a new proposed rule that remedies the specific deficiencies identified by the court in *North Carolina v. EPA*, adopts a reasonable implementation and compliance schedule that allows adequate time for development of SIPs -- rather than impose FIPs in the first instance -- and does not impose emission reduction obligations on affected states that are more demanding than those imposed by CAIR.

Attachment I

Cichanowicz, J.E., "Implementation Schedules for Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Process Equipment" (Oct. 1, 2010).

IMPLEMENTATION SCHEDULES FOR SELECTIVE CATALYTIC REDUCTION (SCR) AND FLUE GAS DESULFURIZATION (FGD) PROCESS EQUIPMENT

October 1, 2010

Prepared by
J. Edward Cichanowicz

Prepared for
Utility Air Regulatory Group

TABLE OF CONTENTS

SECTION 1 EXECUTIVE SUMMARY 1-1

SECTION 2 BACKGROUND 2-1

2.1 PROCESS EQUIPMENT REQUIRED 2-1

2.1.1 FLUE GAS DESULFURIZATION (FGD) 2-1

2.1.2 SELECTIVE CATALYTIC REDUCTION (SCR) 2-3

2.2 ELEMENTS OF A COMMERCIAL PROCUREMENT SPECIFICATION 2-4

2.2.1 CONCEPTUAL DESIGN/PREPARATION OF SPECIFICATION 2-4

2.2.2 IDENTIFICATION OF QUALIFIED CANDIDATE BIDDERS 2-6

2.2.3 SOLICITATION AND REVIEW OF BIDS/SELECTION OF CONTRACTOR 2-6

2.2.4 NEGOTIATION OF CONTRACT TERMS/CONTRACT ISSUANCE 2-7

2.2.5 SECURING PERMITS TO CONSTRUCT AND OPERATE THE RETROFITTED CONTROL EQUIPMENT 2-7

2.2.6 FINALIZATION OF DESIGN AND PREPARATION OF FABRICATION DRAWINGS 2-10

2.2.7 MOBILIZATION OF THE WORKFORCE TO SITE 2-11

2.2.8 ACTUAL CONSTRUCTION 2-11

2.2.9 PROCESS EQUIPMENT TIE-IN 2-12

2.2.10 PROCESS STARTUP 2-12

SECTION 3 FLUE GAS DESULFURIZATION (FGD) SCHEDULES 3-1

3.1 INSTALLATION OF A SINGLE FGD SYSTEM AT A SITE 3-2

3.2 INSTALLATION OF TWO FGD PROCESSES 3-3

3.3 INSTALLATION OF THREE OR MORE FGD PROCESS UNITS AT ONE SITE 3-4

3.3.1 ALABAMA POWER GORGAS UNITS 8-10 (61 MONTHS). 3-5

3.3.2 ALLEGHENY ENERGY HATFIELD'S FERRY UNITS 1-3 (45 MONTHS) 3-5

3.3.3 DUKE ENERGY ALLEN UNITS 1-5 (49 MONTHS FOR THE FIRST RETROFIT; 1 EXTRA MONTH FOR THE OTHER). 3-6

3.3.4 DUKE MARSHALL UNITS 1-4 (46 MONTHS FOR THE FIRST RETROFIT; 6 MORE MONTHS FOR THE OTHER THREE RETROFITS). 3-6

3.3.5 FIRST ENERGY SAMMIS UNITS 1-7 (56 MONTHS). 3-6

SECTION 4 SELECTIVE CATALYTIC REDUCTION (SCR) AND LOW NO_x BURNER SCHEDULES 4-1

4.1 SELECTIVE CATALYTIC REDUCTION (SCR) 4-2

4.1.1 INSTALLATION OF A SINGLE SCR UNIT AT A SITE 4-3

4.1.2 MULTIPLE SCR PROCESSES AT ONE SITE 4-4
4.2 LOW NO_x BURNERS 4-5
SECTION 5 CRITIQUE OF EXAMPLES CITED BY EPA 5-1
5.1 FGD INSTALLATIONS – OVERVIEW 5-1
5.2 EPA EXAMPLES OF FGD INSTALLATIONS BEING COMPLETED IN A TOTAL OF LESS THAN 30 MONTHS 5-2
5.2.1 CENTRALIA WET FGD 5-2
5.2.2 TAMPA ELECTRIC BIG BEND 5-3
5.3 EPA EXAMPLES OF SCR INSTALLATIONS BEING COMPLETED IN A TOTAL OF LESS THAN 30 MONTHS 5-4
5.4 OTHER FACTORS 5-4
SECTION 6 SUMMARY/CONCLUSIONS 6-1
6.1 DEMAND 6-2
6.2 LABOR PRODUCTIVITY 6-2
6.3 ENGINEERING 6-2
6.4 PERMITTING 6-2
SECTION 7 REFERENCES 7-1

LIST OF FIGURES

Figure 2-1. Typical Wet FGD Absorber Tower 2-2

Figure 2-2. Perspective View of SCR Reactor for Coal-Firing (Babcock & Wilcox product information: www.babcock.com/products/environmental_equipment/scr.html) 2-3

Figure 3-1. Timeline of FGD Activities 3-1

Figure 3-2. Sammis Site Layout 3-7

Figure 4-1. Timeline of NO_x Control Projects – SCR 4-1

Figure 4-2. Timeline of NO_x Control Projects – LNB 4-2

Figure 5-1: Timeline Showing Recent Installed FGD Capacity by Startup Date 5-2

LIST OF TABLES

Table 2-1. Lead Time (Weeks) for Key FGD Components (after Katzberger, 2007) 2-2

Table 6-1. Summary of Design, Fabrication, Installation Period 6-1

SECTION 1

EXECUTIVE SUMMARY

This report evaluates the different factors that can affect how long it takes to design, permit and construct flue gas emissions control technologies that power plant owners may have to install on their electric generating units (EGUs) in order to meet the emission reduction requirements that will be included in the United States Environmental Protection Agency's (EPA's) final Transport Rule, which is now scheduled to be published in mid 2011. The control technologies considered by this report as candidates to be used to meet the emission reduction requirements of the final Transport Rule are flue gas desulfurization (FGD) systems for the control of sulfur dioxide (SO_2) emissions; and Low NO_x Burners (LNB) and selective catalytic reduction (SCR) reactors for the control of nitrogen oxide (NO_x) emissions.

In the preamble to its Proposed Transport Rule (published in the Federal Register on August 2, 2010) and in earlier studies upon which EPA now relies (EPA, 2005; EPA, 2002), EPA says that the Agency expects it will take 27 months of total effort for an electric generating company to plan, engineer, install, and start up one FGD system at one unit at a plant site; and that the total effort to retrofit three FGD systems at one plant site might take 36 months. In addition, EPA says that it expects it will take 21 months of total effort for an electric generating company to plan, engineer, install and start up one SCR system at one unit at a plant site; and that it might take about 35 months of total effort for a company to complete the retrofit of 7 SCR systems at a plant site. Also, in the preamble to its Proposed Transport Rule, EPA indicates that it believes it will take less than 6 months of total effort for a utility company to plan, engineer, install and start up a low NO_x burner system at a plant site.

This report includes a broad review of numerous FGD, SCR, and LNB retrofits that have been accomplished during the past ten years, describing each of the key steps that power plant owners must follow in order to be able to install and operate these control technology systems. In addition, this report presents more detailed information about the specific obstacles faced by the plant owners that have recently had to retrofit FGD and SCR systems on their plants, including some obstacles that were not faced by companies having to make such retrofits 5 to 10 years ago.

Following the presentation of background information in Section 1 of this report, Section 2 describes the steps affected power plant owners must take in order to design, permit, and implement one or more SCR or FGD installation projects. Section 3 then presents information on specific FGD retrofits that have recently been undertaken – or are now in the process of being undertaken – by electric generating companies. Section 4 then contains information about recent or ongoing projects for the installation of NO_x controls: SCR and low NO_x burners. The projects discussed in Sections 3 and 4 provide examples of the obstacles that companies now face in undertaking such retrofits, including obstacles they (and others in the industry) may not have faced 10 years ago. Next, Section 5 addresses some of the retrofit cases that EPA cites in its much earlier reports (EPA, 2005; EPA, 2002). Finally, Section 6 summarizes observations and offers alternative, realistic schedules for equipment installation.

SECTION 2

BACKGROUND

This section presents background information, describing the type of equipment retrofit and the key activities involved in undertaking such equipment installations.

2.1 PROCESS EQUIPMENT REQUIRED

The type of process equipment required for a commercial FGD and SCR process is described, highlighting those aspects that affect fabrication and installation.

2.1.1 FLUE GAS DESULFURIZATION (FGD)

The flue gas desulfurization (FGD) system is comprised of four key elements: (a) reagent receiving and preparation equipment, (b) SO_2 absorber tower, (c) byproduct dewatering and management equipment, and (d) a wet stack (optional). The latter wet stack is considered optional particularly if an existing wet FGD process operates at the station, but is usually required for stations without FGD equipment and thus "dry" stacks.

The most visible element of the FGD process is the absorber tower, where flue gas SO_2 contacts finely prepared and dispersed alkali reagent. Figure 2-1 depicts a commercial absorber tower. Most absorber towers can be located near the stack, pending routing of ductwork. Installing or erecting absorber towers requires cranes to relocate material, boilermakers for special-purpose welding, and other special trades and craft workers.

Absorber towers are physically large and their installation has triggered construction delays, particularly where special exotic corrosion-resistant alloys were required for liners. These delays, however, were generally not the project rate-determining step for the FGD equipment installed in 2008-2010.

Rather, what typically caused project schedules to be prolonged in the 2008 to 2010 timeframe was the lack of availability of heavy-duty process equipment: reagent mills (pulverizers) and flue gas fans. In addition, projects were delayed by the limited number of stack erectors: reportedly only 4-6 in the world with what some observers judge to be adequate experience. Katzberger (2007) describes the role of these items in more detail. Of particular note is the role of "ball mills" used to prepare limestone. The order-to-delivery time for this category of equipment escalated from 32 weeks in 2003, to 65 weeks (fall of 2005), 68 weeks (August 2006), 70 weeks (December 2006), and 75 weeks (April 2007).

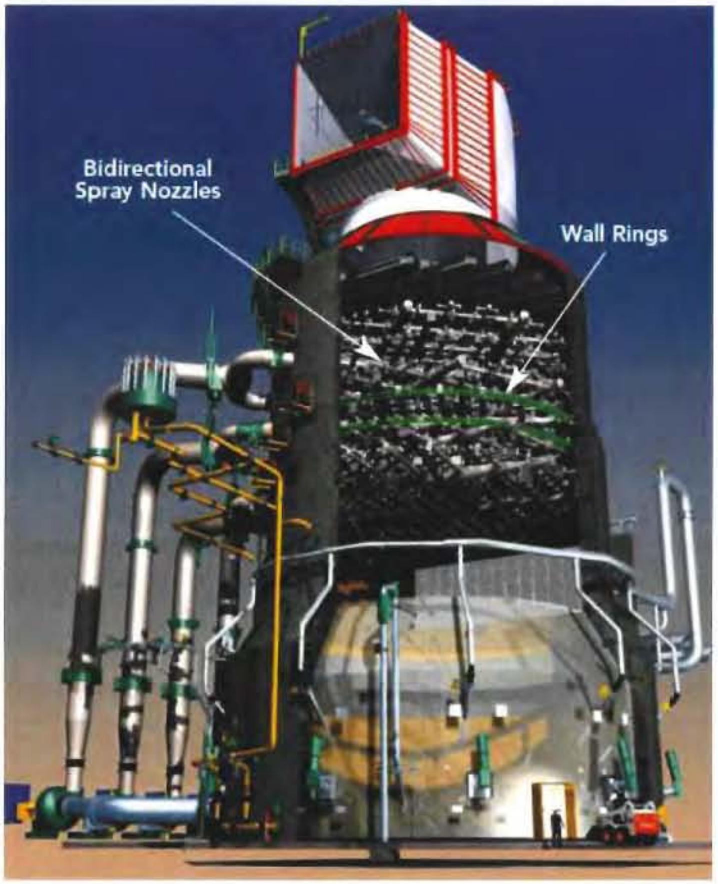

Figure 2-1. Typical Wet FGD Absorber Tower
http://www.babcockpower.com/index.php?option=products&task=viewproduct&coid=17&proid=11)

AEP reports that its most recent (August 2010) attempt to purchase a ball mill resulted in a 90 week delivery schedule from the vendor. Table 2-1 summarizes the escalation in delivery time of ball mills and other key process components.

Table 2-1. Lead Time (Weeks) for Key FGD Components (after Katzberger, 2007)

	Lead time (weeks)			
Equipment	**Sept. 2003**	**Oct. 2005**	**Aug. 2006**	**Dec. 2006**
Ball mills	32	65	68	70
Rubber-lined recycle pumps	26	52	92	112
Booster fans	NA	54	54	60
Oxidation air compressors	32	44	44	52
Internal-recycling alloy spray headers	28	40	40	48

Note: NA = Not available.

Transformers and switchgear can also be long-lead items, with some companies reporting that it took more than 100 weeks to get delivery of such items.

In addition, companies have reported extensive delays in the overall installation process caused by the need to get a broad array of permits and authorizations for SCR and FGD installations. As discussed more below, plant owners must have some of the needed permits and authorizations in hand before they can begin most of the site work for FGD and SCR installations.

2.1.2 Selective Catalytic Reduction (SCR)

Unlike the case for FGD, SCR process reactors are installed within the "heart" of the plant layout – extracting gas from the economizer exit and returning it to the air heater inlet. This location is necessarily constrained, as plant design did not envision access for such large equipment. Figure 2-2 depicts a typical SCR reactor. Finding space for and retrofitting such equipment is challenging at all sites.

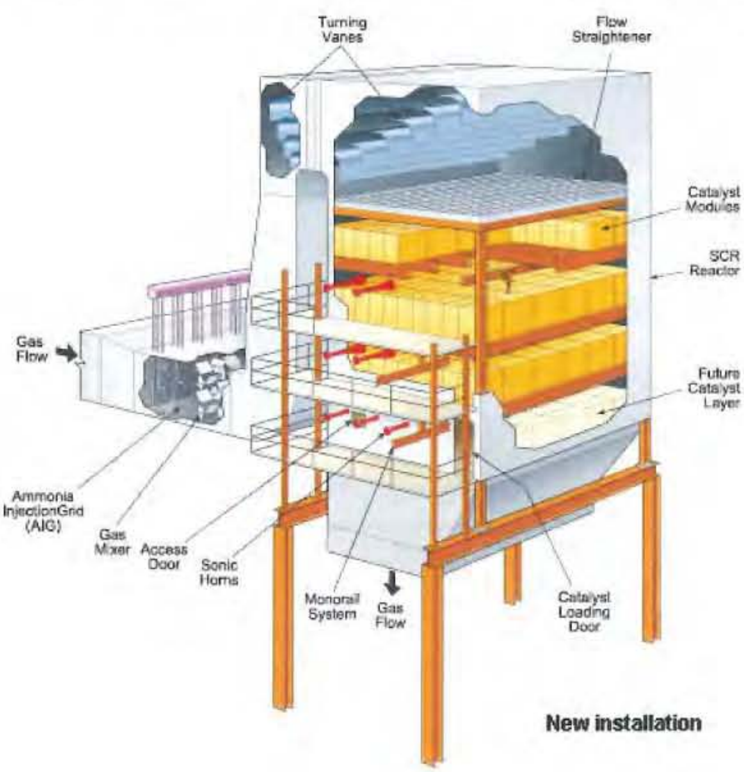

Figure 2-2. Perspective View of SCR Reactor for Coal-Firing (Babcock & Wilcox product information: www.babcock.com/products/environmental_equipment/scr.html)

2.2 ELEMENTS OF A COMMERCIAL PROCUREMENT SPECIFICATION

This section addresses the steps in a project to design, procure, and install process control equipment such as SCR and FGD.

It is convenient to consider the required activities as ten separate steps. Many of these steps can be conducted in parallel but some must be sequential.

Each of these steps is described in the following text:

- Conceptual process design and preparation of specification
- Identification of qualified candidate bidders
- Solicitation and review of bids; selection of contractor
- Negotiation of contractual terms and conditions, and contract issuance
- Securing environmental permits and other needed authorizations and approvals
- Finalization of the process design and preparation of fabrication drawings
- Mobilization of the workforce to site
- Actual construction
- Process Equipment Tie-in
- Process Startup

Each of these key steps is further described in this section.

2.2.1 Conceptual Design/Preparation of Specification

As part of developing a conceptual design for FGD or SCR systems, it is necessary for the power plant owner to select the specific type of equipment to be applied, determine the feasible range of control efficiency, identify potential byproducts from operation of the new control equipment, and project the capital and operating cost range. Also, as part of conceptual design, a power plant owner must identify any site characteristics or requirements that could make it more difficult – or more expensive – than is typical to install and operate the proposed new equipment. This step will require at least several months but typically takes 6-12 months, depending on site complexity. The owner of a large, multi-state system reports that taking 9-12 months to complete this process is a prudent way to minimize risk and avoid cost overruns.

Numerous other items can prolong this activity. These include the need to (a) undertake a thorough review and solicitation of available fuel suppliers, perhaps qualifying new fuel sources – particularly for conventional wet limestone FGD, which may allow the firing of coals with higher sulfur content not historically used at a station; (b) make a detailed characterization of site conditions, including soil characteristics, the presence of underground utilities, and available water for process make-up; and (c) develop a detailed description of how the unit will operate over the future decades (which is not necessarily the same as historical operations).

This and other preconstruction steps typically take over 12 months to complete. Some companies – particularly those operating multiple EGUs at multiple sites – may be able to take actions to reduce the time needed for engineering and for the procurement process (which is discussed below). Specifically, it may be possible for a plant owner to reduce engineering and procurement timelines to a year, or just under one year, by establishing a common-design absorber and other process equipment.

The best example of this is Duke Energy, which has used a common-design absorber and auxiliary equipment in the retrofits of FGD systems at 12 individual units at 4 generating stations in North Carolina – 4 units at Marshall, 2 at Belews Creek, 5 at Allen, and 1 at Cliffside (McCarthy, 2004). When Duke engaged Alstom to evaluate such an approach in 2003, it was at a point when none of the Duke units in North Carolina had yet deployed FGD. Because Alstom was working on such a relatively clean slate and because the fuel sources were relatively consistent, Alstom was able to develop for Duke's North Carolina plants a system-wide design for FGD absorbers and support equipment. A combination of these components was used in all applications in North Carolina, which reduced engineering and procurement actions.[1] As a result of this effort, completion of the engineering and procurement steps for FGD installations at each affected Duke plant in North Carolina generally took a year or just under one year.

(Notably, McCarthy (2004) reports that each station underwent a two-phase engineering analysis in order to ensure that the work to be done was properly described. The first phase established the design basis (gas flow rate, gas composition, available reagent composition), optimized a standard absorber design, established balance-of-plant needs, and developed a layout and preliminary cost. The second phase addressed details of balance-of-plant and auxiliary equipment, and developed detailed contracts for fabrication and construction schedules by which to manage the work and hold subcontractors accountable. Each phase reportedly required 6 months. Such attention to detailed design is necessary, for either approach that emphasizes a system versus an optimized individual unit design. Before awarding contracts valued at several hundred million dollars, any less effort in the present activist climate could invite prudency challenges.)

Similarly, Southern Company employed common process designs developed by two suppliers – Chyoda Corporation and AdvaTech LLC – in assembling an FGD strategy for 12,000 MW of capacity (Wall, 2010).

[1] After the system design strategy was conceived for Duke Energy's Carolina units in 2003, Duke Energy merged with Cinergy in May of 2005. It was not possible to use the "Carolina approach" for the former Cinergy plants, but Duke was able to use alternative design approaches for the former Cinergy plants, based on those plants' considerable experience with higher sulfur fuels.

The use of a system-wide engineering approach may not be applicable, or provide high payoff, to all owners. This approach may not be beneficial to small systems – those with 1 or perhaps 2 units. Also, owners of large multi-state systems – that have in-place "legacy" FGD equipment on existing units, and that have developed significant expertise and experience with coals native to their systems – may not fully benefit from common design approaches.

2.2.2 Identification of Qualified Candidate Bidders

Once the scope of the project is defined, owners can start to identify the candidate bidders for the project, i.e., vendors that are qualified to satisfactorily deliver and install the components of the project. To take advantage of competitive forces that can reduce the price of a project (and to avoid prudency challenges that can arise from seeking bids from only one provider), power plant owners typically want to receive bids from a broad list of candidates. Because of the high cost involved to prepare a bid in response to a request for proposal (RFP), and to review the bids, good business practice leads most power plant owners to solicit bids only from suppliers believed to be qualified.

This step in the procurement process is also, however, intended to eliminate the possibility of limited or no bids, which can force plant owners to start the whole process over again. The possibility of this happening is very real. Katzberger (2007) noted that in 2007 some RFPs received one – or in some cases no – qualifying bids.

This step typically requires at least 1 month. The most common delays are those resulting from potential bidders in submitting financial surety and market "backlog" data, which is important particularly in constrained (i.e., sellers) markets.

2.2.3 Solicitation and Review of Bids/Selection of Contractor

The process of deciding which suppliers to use is not based solely on cost. Many other factors must be taken into account in order to assure that the best long-term solution is found, one which will assure approval by both management and, in the case of regulated companies, by PUC staff.

This goal is factored into the process of soliciting and reviewing competitive bids. In particular, the bid solicitation process requires issuing a detailed process specification, hosting a bidder meeting and site inspection, reviewing the submitted bids, and selecting the successful contractor. Generally, bidder meetings and site "walkdowns" are held within 2-3 weeks of issuing the specification, although this part of the process can often take 4-6 weeks in the case of large, multi-unit projects. A minimum of 30 days following the site inspection is required to prepare a bid. Review of bids will be conducted by power company staff or designated engineering firms. The successful supplier is selected based on numerous factors, including relevant experience, ability to meet projected schedule, experience in containing cost, and historical performance on similar projects.

This entire step typically requires 3-5 months but can take longer, depending on the need for follow-up to clarify issues and proposed responses. For example, the development of an adequate bid in response to an engineering specification can take longer when demand on equipment and suppliers is high.[2] Also, the time for completing this part of the process can be extended when plant owners receive inadequate or partially responsive bids, need addendum or additional submittals from bidders, or must seek clarifications of the responses they get.

2.2.4 Negotiation of Contract Terms/Contract Issuance

Once the preferred contractor is selected, that contractor and the plant owner must agree to acceptable terms and conditions. The framework of acceptable terms and conditions is defined in the specification, and bidders in their proposals can take exceptions to the proposed conditions. All these details cannot be resolved in the proposal process.

After the preferred contractor has been selected, the time it will take to finalize contract terms will depend on several factors, including whether the plant owner and contractor have previously worked together and the nature of the contract terms. For example, it may take 1-2 months to negotiate standard terms and conditions where the plant owner is familiar with and has previously worked with the contractor. For larger projects where the plant owner and selected party have not previously worked together, it can take longer – sometimes as long as 3-5 months. Also, the negotiation of non-standard terms and conditions can add time to the overall process. One example is the financial surety details – how much, if any, of a financial bond must be posted, or the damage provisions of a contract in the event of non-performance. For projects that are conducted as an open book alliance, the rate structure of relevant personnel and the financial incentives and penalties to reward or penalize performance can require lengthy financial and legal analysis.

2.2.5 Securing Permits to Construct and Operate the Retrofitted Control Equipment

Securing all pre-construction permits needed for the design and installation of pollution control projects can be a time-consuming process – but companies can incur legal liabilities and run other risks if they start installation before they have key permits in hand. Thus, the typical approach is for companies to finalize the conceptual design of equipment and to have in place the major contracts and then – armed with detailed information – they are in the best position to start the process of getting all needed permits and other regulatory authorizations.

[2] Not surprisingly, almost without exception, it has been possible to accelerate project schedules only during times when demand on equipment and suppliers was low.

As part of this step, plant owners will not only need to get permits governing the treatment of flue gas emitted from the retrofitted control equipment, but also to get other environmental permits (to cover other emissions of air pollutants, water discharges, and the treatment of waste water and the management of solids byproduct) and a broad array of other authorizations (for example, from zoning boards and public utility commissions). As just noted, although parts of the installation process can go forward in parallel with the permitting/authorization process, some permitting programs prohibit a company from going too far in the construction process without first getting specific pre-construction authorizations. And getting all those authorizations has become much more time-consuming and complicated during the past five years, thus making it a possible major bottleneck for the installation of FGD and SCR systems. This is especially the case for power plant stations at which FGD and SCR control systems have not previously been installed. There are many reasons that permitting has recently become more complicated and time-consuming, including but not limited to the following.

Increased Difficulties in Getting Preconstruction Permits Under the Clean Air Act. The operation of SCR and FGD units will significantly reduce emissions of NO_x and SO_2, respectively, but operation of that control technology may result in a "collateral increase" in emissions of a byproduct species other than NO_x or SO_2. For example, the operation of wet FGD and SCR – while reducing SO_2 and NO_x emissions – may increase sulfuric acid mist by more than insignificant amounts. Also, operating low NO_x burners will reduce NO_x emissions but under some conditions have been thought to increase carbon monoxide (CO) emissions. Concern for a possible increase in CO emissions may delay permit approval by some agencies. (Recent installations of LNBs, in conjunction with improved combustion controls, have not increased carbon monoxide emission rates.)

The new source review preconstruction permitting program can be triggered by projects that will result in a significant net emissions increase of one or more regulated pollutants. Prior to late 2005, projects that installed environmental control equipment did not trigger the time-consuming new source review preconstruction permitting process because such projects were subject to the pollution control project exclusion (PCP exclusion) in EPA's new source review (NSR) rules. In December 2005, a court decision vacated the PCP exclusion. As a result, the NSR permitting process may be triggered by a project to install an FGD, SCR or LNB system, if the operation of that control system may result in the increase of a pollutant other than the pollutant being controlled by the FGD, SCR or LNB unit.

Having to obtain a new source review permit could delay installation of the new control system because of the elaborate procedures associated with NSR permitting. For example, the process of obtaining a new source review permit prior to the beginning of construction for FGD or SCR units, even if consisting of no more than a paper exercise, can add many months to the overall process. And if a full-blown review is needed (perhaps to evaluate emissions of greenhouse gases once the NSR process is scheduled to start applying to greenhouse gas emissions in early 2011), that could add a year or more to the entire process.

NSR provisions were not a problem faced by companies installing pollution control projects in the first part of the last decade.[3] Thus, the two key SCR examples cited by EPA – those at the Kintigh and Keystone stations – were retrofits that did not address the NSR implications of enhanced SO_3 emissions.

Permits Governing Byproduct Management. In addition to securing permits authorizing the release of air pollution associated with the operation of pollution control systems, power plant owners also must secure permits to address other environmental consequences of operating such equipment, including permits for the treatment and/or storage of the byproducts of both wet and semi-dry FGD systems. For a variety of reasons – including public concerns over coal ash management that have prompted examination of the benign byproducts of both wet and semi-dry FGD, such as gypsum – addressing this issue can now take 4 to 5 years.

Some of the specific examples presented in Sections 3 and 4 of this report demonstrate that securing a land use management permit for FGD byproducts can take longer than four years and can itself be an absolute impediment to the installation of a complete system in under 30 months. For example, AEP reports instances in which the time from preparing the permit application for a landfill to the first storage was 40-42 months. (As discussed in separate comments being filed by AEP, this was the case for the Cardinal and Mountaineer FGD projects). Also, Georgia Power Company reports that it took over 48 months to obtain a preconstruction permit for a byproduct management site and an additional 14 months to complete construction of that installation, a total of over 60 months.

It can also take time to secure the necessary permits to authorize use of a separate byproduct management site not located on plant property. AEP reports that the permitting process for a separate byproduct management site located remote from an existing site can add 10 to 20 months to a project schedule.

Examples from Duke Energy in North Carolina also demonstrate this point. Duke staff report the timeline to secure a workable landfill on plant property in their possession has been 42-48 months (Hallman, 2010). This timeline includes locating and assessing the suitability of the site (18-22 months), securing the permit to construct (10-12 months), construction (12 months), and securing the operating permit (2 months).

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[3] Although a company may be able to avoid triggering the NSR permitting process by adding other controls to reduce emissions of collateral pollutants, that will not necessarily shorten the overall permitting process. Specifically, adding pollution control equipment to reduce emissions of collateral pollutants means going through the above-listed steps – including engineering design, solicitation of bids, permitting, etc. – before those additional pollution control systems can be constructed.

Public Utility Commission (PUC) Approvals to Install Pollution Control Equipment. Where PUC approvals are needed, the length of time it can take to seek and receive such approvals can vary widely, from 6 months to more than one year. For example, AEP reports that in one state in which it owns generating units (Kentucky), the PUC – after receiving an application – typically takes 9 months to act on that application. Another example comes from Minnesota: the Minnesota PUC required 18 months to approve plans by Xcel Energy's Northern States Power (NSP) subsidiary, for a series of environmental upgrades (Hansen, undated). These upgrades included applying SCR and dry FGD with a new baghouse to NSP's King Station, in addition to repowering smaller units with natural gas combustion turbines.

Other Authorizations. Individual companies point to other, more site-specific permitting issues that have arisen or are likely to arise when they seek permits to install FGD or SCR systems. For example, some companies report that the operation of pollution control equipment will result in discharges that will trigger the need for revisions to source Clean Water Act permits. For discharges into some water bodies (e.g., those that have stringent restrictions on discharges of any additional nutrients), that permitting process could be extremely difficult and time-consuming. Other companies point to the increasing regulatory uncertainty surrounding effluent guideline regulations, noting that such uncertainty can hinder the decision-making process and make the process iterative if regulations require additional changes or alterations to the plant not anticipated in the original permit applications. Yet other companies note the regulatory complications involved in locating, constructing, and operating pollution control equipment in urban areas, where they may face zoning challenges, restrictions on the truck traffic related to such operations, and even height restrictions if equipment is to be located near an airport.

In summary, completion of this step will routinely take two years and can often take up to 4 years, making it a major impediment to the completion of FGD and SCR installations in less than 30 months.

2.2.6 Finalization of Design and Preparation of Fabrication Drawings

The engineering contractor will finalize design and fabrication drawings. These detailed drawings provide specific instructions as to what type of equipment to procure and install.

Final design begins almost immediately after the engineering or supplier contractor is selected and will last for 15 to 45 months. Most delays in preparing the final design are due to identifying site limitations or constraints that are not obvious at preliminary design – such as the presence (or lack of) underground utilities or other structures, or soil properties. Much of this process can be conducted in parallel with other equipment installation activities.

2.2.7 Mobilization of the Workforce to Site

Securing the construction services of key trades and crafts staff must be executed promptly upon execution of construction contracts. When there are not a significant number of competing projects going on simultaneously, this can be accomplished in 1 to 3 months. It can take longer, however, when there are a significant number of similar projects underway and competing for the same skilled workforce. Significant regional differences in workforce availability or mobility can affect this element of construction.

2.2.8 Actual Construction

Construction activities are initiated immediately following mobilization of the workforce to the site. Typically, progress is accomplished according to a rapidly accelerating rate, starting with preparation of the site for laydown area, assembling necessary equipment, and initiating concrete and foundations work.

Of course, construction cannot start until the necessary fabricated and raw materials can be delivered to the site. The extensive delays in delivery of the key components defined in Table 2-1, as well as electrical and switchgear components, had a significant impact on FGD construction schedules in the 2008-2010 timeframe. The lack of availability of key components could also adversely affect FGD and SCR installation schedules in a future 2012 to 2014 time frame.

Although some fabrication work can take place off-site, restrictions on the size of process equipment that can be transported limit the amount of off-site fabrication. The physical size of the SO_2 absorber tower in Figure 2-1 and of the SCR reactor in Figure 2-2 indicates that most construction must occur on-site.

The length of time it will take to complete the construction process will vary from site to site depending upon several key factors: the complexity of the site and the presence of other in-plant equipment, access to the site and limits on where the cranes required to install heavy equipment can be placed, the amount of existing equipment demolition or relocation, and site remediation. For example, as will be described in Section 4 of this report, the SCR reactors at First Energy's Sammis facility could not be installed until contractors first removed from the site the original equipment ESPs, which had been abandoned "in-place" when new particulate control equipment was installed. Also, the highly publicized retrofit of wet FGD to PSNH Merrimack required two years of site preparation, and one year of major construction (PSNH, 2010).

Also, the productivity of construction labor is key, and there can be significant differences in regional workforce productivity, which can affect installation schedule. Experience with the equipment retrofits in 2008-2010 showed a strong demand for the most experienced and productive staff. Consequently, the skilled trade craft assigned to later-in-the-pipeline projects – often projects being undertaken by smaller companies, seeking to complete only 1 or 2 retrofits – tended to be the less experienced and less productive staff. Finally, timely access to equipment – avoiding delays in delivery of equipment – must be minimal.

Construction timelines under the best conditions have been about 25-30 months, with more complex sites requiring more than 40 months. For multiple units, the construction timeline can extend for several years.

2.2.9 Process Equipment Tie-In

Following actual construction of the control equipment, a unit outage is necessary to tie in process ductwork to an existing unit. Companies usually try to conduct tie-in activities during or near planned outages, but such outages are typically not scheduled solely for the purpose of equipment tie-in, and such outages are never scheduled during peak load periods. Also, in cases involving more complicated installations, the tie-in process will likely extend beyond the time usually set aside for outages.

In some cases, the equipment tie-in process can be accomplished in as little as 3-4 weeks, but this process will require up to 3 months at sites where conditions are more challenging. For example, at TVA's Bull Run Station, a 10-week outage was required for tie-in of the FGD process. This 10-week period was due to the complex ductwork arrangement that prevented the use of conventional modular construction methods; also, the FGD retrofit required the company to make changes to the air heater and forced draft fans. Another example would be the retrofit of SCR at Georgia Power Scherer Unit 3. That effort required a 3 month outage due to the complexity of ductwork. Similarly, the tie-in period required to install SCR at Unit 4 of Plant Hammond was 7 weeks – simply due to the inability to get cranes close to the ductwork to be penetrated.

2.2.10 Process Startup

Once the equipment is installed and tied in, it generally takes at least 30 days and can take up to 90 days of shakedown operations, testing, and process tuning before the power plant owner will take over unit operations. In some instances a process shutdown and re-start is required to mitigate a performance issue.

In summary, there are numerous steps involved in the design permitting and construction of SCR or FGD process equipment, only a few of which can be conducted in parallel. And the overall period of time that it will take to complete the entire installation and design process will depend upon many factors including, for example, the size and configuration of the site at which equipment is being installed, whether (for FGD installations) the process equipment is located at a site where

FGD already exists, and whether the site has in place a permitted facility for byproduct management. As discussed in the following sections of this report, factors like this will lead to FGD and SCR installation schedules far in excess of the 30 months that EPA has cited.

SECTION 3

FLUE GAS DESULFURIZATION (FGD) SCHEDULES

This section of the report discusses the installation schedules of several recent (or ongoing) FGD projects. The projects discussed demonstrate that the timetable for completing such installations can vary significantly, depending upon many factors, including the nature of the site and whether the host is a single unit or one of multiple FGD processes to be installed at a station.

Figure 3-1 presents a summary timeline for representative FGD projects, depicting when engineering and procurement start, and construction begins. The stations represented in Figure 3-1 are from those FGD owners who could expeditiously provide the requested schedule information within the abbreviated time required for preparation of this report. Despite attempts to authentically reflect the distribution of the 1,500 generating stations in the U.S., it is not known if the stations in Figure 3-1 reflect a true statistically representative sample. Consequently, the trends between different categories of units will be approximate. Figure 3-1 shows a wide variety of project duration schedules.

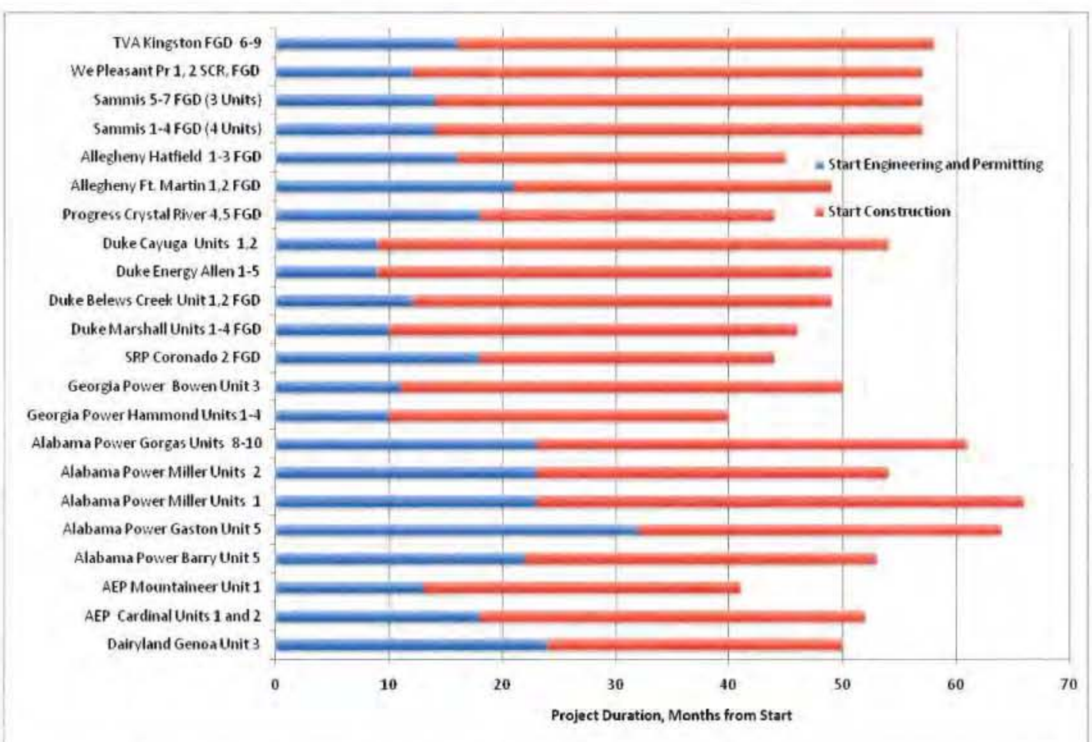

Figure 3-1. Timeline of FGD Activities

The following is a more detailed discussion of many of these FGD installation projects. The examples include what might be considered "best case" scenario installations of a single FGD process at one site. There are also examples of more challenging installations, including multiple FGD installations at a generating station with multiple units. These examples also include stations that are contemporaneously retrofitting SCR and FGD systems.

3.1 INSTALLATION OF A SINGLE FGD SYSTEM AT A SITE

How long it will take to add a single FGD process at a site will depend on the specific details of the site. For example, retrofitting an FGD process to a site already equipped with one or more FGD units – and where there is already a licensed byproduct management system at the site – is likely to present a more straight-forward engineering and installation situation than will be faced when a company installs FGD at a site that is not already equipped with one or more FGD units.[4] However, other site-specific factors can override any such advantage. Consequently, for the purposes of this discussion, stations with and without FGD are placed in the same category for discussion.

As shown in Figure 3-1, examples in this category include the installation of the FGD unit at Alabama Power's Barry Unit 5 (which took 53 months); the retrofit of an FGD system at Georgia Power's Hammond facility (which took 40 months); the retrofit of an FGD system at AEP's Mountaineer facility (which took 42 months to complete); the retrofit of FGD at Georgia Power's Bowen Unit 3 (which took 50 months); the FGD retrofit at Alabama Power Gaston Unit 5 (which took 64 months); and the installation of FGD at Salt River Project's Coronado Unit 2 (which took 44 months even though the plant owner was willing to pay additional local agency fees and assign contactors to expedite the permitting process and accelerate review).

The case of Georgia Power's Plant Hammond installation is an example of a short-to-average-time installation schedule. The single FGD module for four boilers at Hammond was implemented in the shortest schedule incurred by this owner. Several factors enabled this abbreviated schedule. First, the process and absorber design developed for other sites was applied, shortening the period for procuring contracts. Second, certain design tasks were accelerated as they were leveraged on previous, similar applications. Third, as described in greater detail in comments being filed separately by Southern Company, ample and accessible space was available to allow simultaneous construction of equipment such as the absorber and reagent preparation facilities.

[4] As will be noted in Section 5, one of the four reference units selected by EPA (Tampa Electric Big Bend) represents this case. There, the existence of reagent receiving, processing and handling systems for two other, FGD-equipped units at the site supported expedited design and construction for Units 1 and 2.

In contrast, there was a 64-month schedule for installation of FGD at Alabama Power's Gaston Unit 5. This reflects the impact that a more complicated site can pose for a source owner trying to install control equipment.

Another factor that should be considered is whether the plant owner operates a large fleet of plants or only a few units. Owners in the latter category – without the market power of large, multi-state operators – will have less leverage over suppliers and can expect longer installation times. The relatively small market presence of Dairyland Power Cooperative is believed to contribute to the 50 month installation schedule for retrofit of semi-dry FGD. As described by Katzberger (2007), it is not uncommon for small operators to not receive the same degree of response as larger owners.

In summary, during the past five years, the average time incurred to retrofit FGD on a single unit at a site has been 48 months, but it has recently taken some companies less time to complete such a single retrofit (as little as 40 months) and it has taken other companies more than 60 months to complete a single retrofit. The difficulties faced by large companies are magnified for smaller companies.

3.2 INSTALLATION OF TWO FGD PROCESSES

Implementing two FGD units at a site can affect an overall FGD installation schedule. For example, by undertaking multiple installations, the per-unit design timelines may be shorter, but the overall construction schedule may have to be extended due to the number and complexity of site activities. Usually the additional time is due to the availability – or unavailability – of space during construction. For example, in the ideal case, major equipment to be installed is temporarily stored in a "laydown" area adjacent to the final location, where final preparation can take place. The distance between the laydown area and installation site ideally is minimal, and a single installation can usually be supported. However, in many cases, an adequate laydown area for two units cannot be found adjacent to the site. As a result, there are longer transport distances and there may be a delay in the final preparation preceding installation.

There are numerous examples of FGD retrofits that fall into this category. These include Duke Energy's Belews Creek Units 1 and 2 (which took a total of 49 months: 12 months of project work and 37 months of construction for the first unit to be operable) and Cayuga Units 1 and 2 (54 months: 9 months of project work and 45 months of construction); Allegheny Energy's Ft. Martin Units 1 and 2 (40 months plus an additional 9 months to relocate existing byproduct settling lagoons); and AEP's Cardinal Units 1 and 2 (52 months).

Also being included in this category are the FGD projects at WE Energies Pleasant Prairie Units 1 and 2 and Progress Energy Crystal River Units 4 and 5, where plant owners contemporaneously constructed FGD SO_2 control systems and SCR NO_x

control systems. This type of project can take more time than "single FGD system" retrofits due to size of the entire project – a greater amount of concrete to be poured for foundations, electrical cable installed located for power and instrumentation and controls, fabricated steel vessels to be stored and prepared for erection in limited "laydown" space, cranes to be positioned for installation, and access and working space for hundreds of boilermaker and other skilled trades. Completion of the FGD installation at WE Energies' Pleasant Prairie Units 1 and 2 took 56 months; and completion of work at Progress Energy's Crystal River Units 4 and 5 took 44 months.

One factor contributing to the fact that the design and engineering phases of Duke's installations may, on average, have taken less time than those steps took at some of the other above-listed installations is that Duke – by adopting a system-wide FGD design – was able to initiate construction sooner. Not all owners can adopt this approach, based on the variety of generating units and the presence of FGD on existing units.

Site differences can also elongate a construction schedule. The case of Allegheny Fort Martin is instructive on this point. The cited installation schedule of 40 months does not include an additional 9 months to relocate existing byproduct settling lagoons to accommodate the reagent storage and preparation, gypsum dewatering, and waste water treatment facilities. In addition, the subsurface area beneath the former lagoons required caissons for support. This site was very congested and required a step-by-step erection process instead of erecting multiple facilities simultaneously. For example, the stack shell was first erected, followed in sequence by the Unit 2 and Unit 1 absorber island. Site constraints forced the absorber shell to be erected in "rings" at the north end of the plant, transferred by barge to the south end of the plant, and welded section by section. The shared facilities such as reagent unloading, storage and processing, gypsum dewatering and storage, and waste water treatment were all separated from the absorber island. Consequently, significant pipe and electrical racks were necessary to connect all facilities. In addition, finally, labor productivity was not optimal – construction craft had to be bussed to the work site each day from a parking area that consumed valuable work time.

In summary, the average retrofit time for these installations was 47 months but – as was the case with the previous category – there was great variation, with some installations taking less time and others taking much more.

3.3 INSTALLATION OF THREE OR MORE FGD PROCESS UNITS AT ONE SITE

Implementing three or more FGD processes at a site can lead to even greater difficulties as the challenges for two units are extended. The limits of space and access for manpower are greater.

The following examples of this category of FGD retrofits are discussed below: Alabama Power Miller Units 1-4; Allegheny Hatfield's Ferry Units 1-3; Duke Energy Allen Units 1-5; Duke Energy Marshall Units 1-4; First Energy Sammis Units 1-7; and Alabama Power Gorgas 8-10. TVA Kingston Units 6-9 are also reflected in Figure 3-1.

As demonstrated by the following discussion, it took an average of 49 months for owners of these units to install three or more FGD systems at one site. The least required time was 45 months; in two instances it took 56 months or more to complete installation of FGD at the first unit at the site, with subsequent units requiring additional time.

The reasons why FGD installations at each of these took more than the 27 months that EPA suggests is standard is that there is nothing standard about most power plant sites.

3.3.1 Alabama Power Gorgas Units 8-10 (61 Months).

The 61 month schedule for Gorgas was the longest incurred by this owner. There were several key reasons for this extended schedule. First, as the initial FGD project for this owner, the engineering required significant time as did negotiating contracts. Second, the site required extensive modifications – literally moving a small mountain to create the adequate space. The limit on space forced the new stack to be constructed sequentially, and not in parallel with other equipment. Further, significant improvements to the flue gas handling system – including upgrade of fans – were required.

3.3.2 Allegheny Energy Hatfield's Ferry Units 1-3 (45 Months)

The Hatfield's Ferry site is very hilly and required significant site earth movement to create "benches" to install the induced draft fan, absorber island, and the reagent process and material handling equipment. Each of these areas is located over an abandoned coal mine that required stabilization by injecting a flyash/concrete mixture. A caisson structure was also required to further provide structural support. Prior to construction, transmission lines (500 KV) from the generating unit to the switchyard had to be relocated to provide clearance for cranes to erect the induced draft fan and absorber facilities. Due to lack of laydown space near the unit, the absorber vessel shells were built off site, shipped to the site and erected ring by ring. Finally, the shared facilities such as reagent unloading, storage and processing, gypsum dewatering and storage, and waste water treatment were all separated from the absorber island. Consequently, significant pipe and electrical racks were necessary to connect all facilities.

3.3.3 DUKE ENERGY ALLEN UNITS 1-5 (49 MONTHS FOR THE FIRST RETROFIT; 1 EXTRA MONTH FOR THE OTHER).

Two FGD units were installed to serve the five units at Duke Energy's Allen Power Plant, where the units are relatively small and several boilers feed one of two FGD absorbers. It took a total of 49 months to bring on-line the first FGD unit and an additional month to bring the other FGD unit on line.

3.3.4 DUKE MARSHALL UNITS 1-4 (46 MONTHS FOR THE FIRST RETROFIT; 6 MORE MONTHS FOR THE OTHER THREE RETROFITS).

Duke Energy installed 4 FGD units at its Marshall Power Plant. The first FGD installation to be completed was at Marshall Unit 4, which took 46 months. It took an additional 4 months to complete work on the second retrofit and another two months to complete work on the remaining two retrofits.

3.3.5 FIRST ENERGY SAMMIS UNITS 1-7 (56 MONTHS).

A notable case is that of Sammis Units 1-7. Figure 3-2 depicts the Sammis site layout, adjacent to the Ohio River, with Ohio State Route 7 located below the ESPs and fabric filters built in the 1980s for these units, and three 800 MW FGD absorber towers. Flue gas from the entire station – all 7 units – is treated by these three absorber towers. (SCR process equipment is located on Units 6 and 7.) Figure 3-2 shows the Sammis site is bounded by the Ohio River and a rail line – which, among other factors, constrained construction activities and contributed to the extended installation time of 56 months.

Figure 3-2 also indicates where that two 600 MW SCR reactors were installed within the boilerhouse building.

In summary, owners of major generating stations have required a total of between 45 and 66 months to retrofit 3 or more FGD systems at one site. The length of time it took to complete FGD installations at the different sites varied depending upon site-specific factors. For example at Duke's Marshall station, the first unit (Unit 4) became operational 46 month after start of engineering and permitting, with the three remaining units coming on-line over the next 6 months. At Alabama Power's Miller station, three FGD units are on line and one is scheduled to come on-line in 2011; the total installation time for each of the four retrofits ranges from 54 months to 66 months.

The common theme in these retrofits is the extensive number of activities to be conducted within a limited, confined space, which requires many activities to be conducted sequentially and not in parallel.

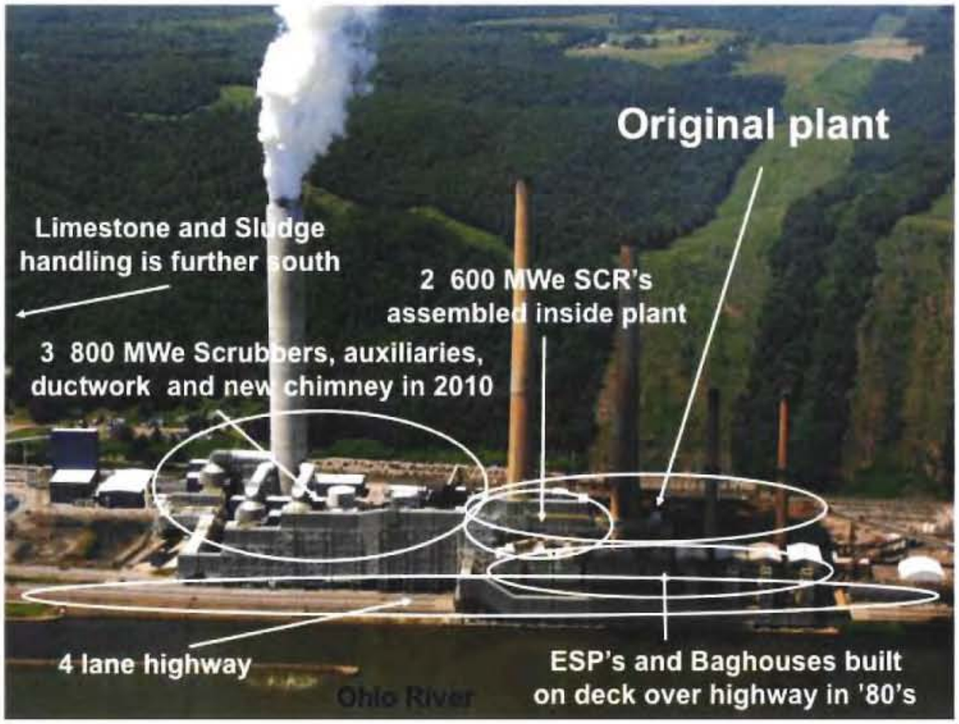

Figure 3-2. Sammis Site Layout

SECTION 4

SELECTIVE CATALYTIC REDUCTION (SCR) AND LOW NO_X BURNER SCHEDULES

This section of the report reviews the schedule to retrofit SCR reactors and/or low NO_x burners at 13 generating stations. A summary of the results for SCR is presented in Figure 4-1, and for low NO_x burners in Figure 4-2.

The stations represented in Figures 4-1 and 4-2 are those of plant owners that retrofit SCR and low NO_x burners and that could expeditiously provide the requested information within the time required for this report. As with the case for FGD experience summarized in Figure 3-1, it is not known if the stations in Figure 4-1 reflect a statistically representative sample. Consequently, the trends between different categories of units will be approximate.

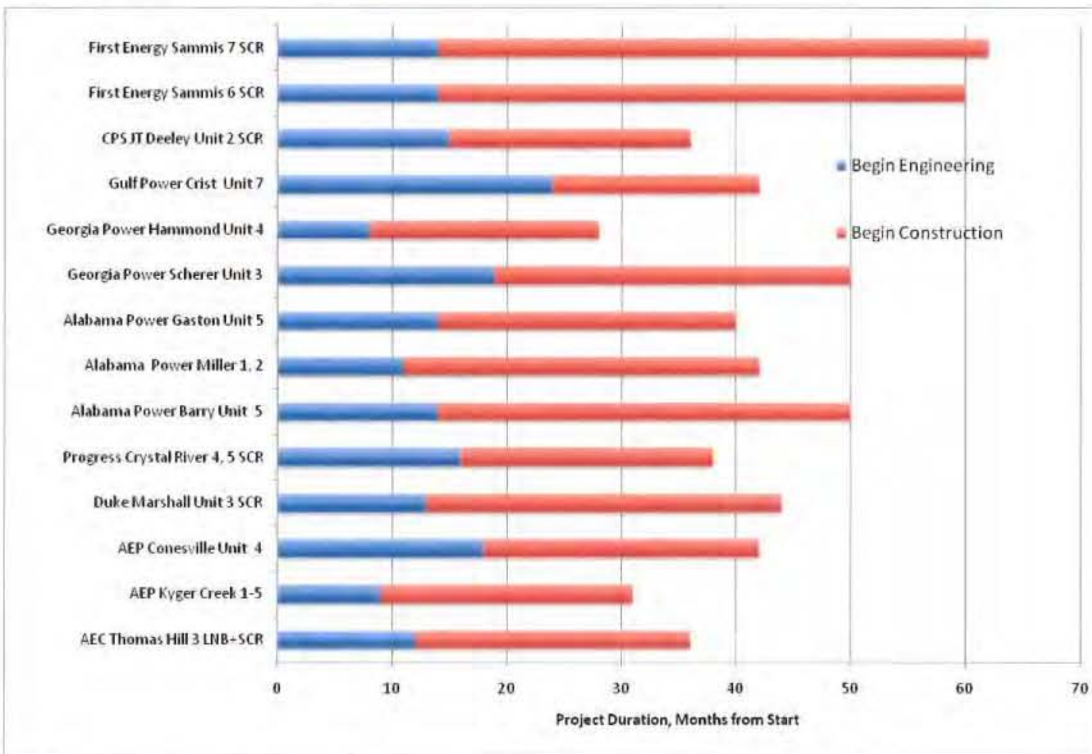

Figure 4-1. Timeline of NO_x Control Projects – SCR

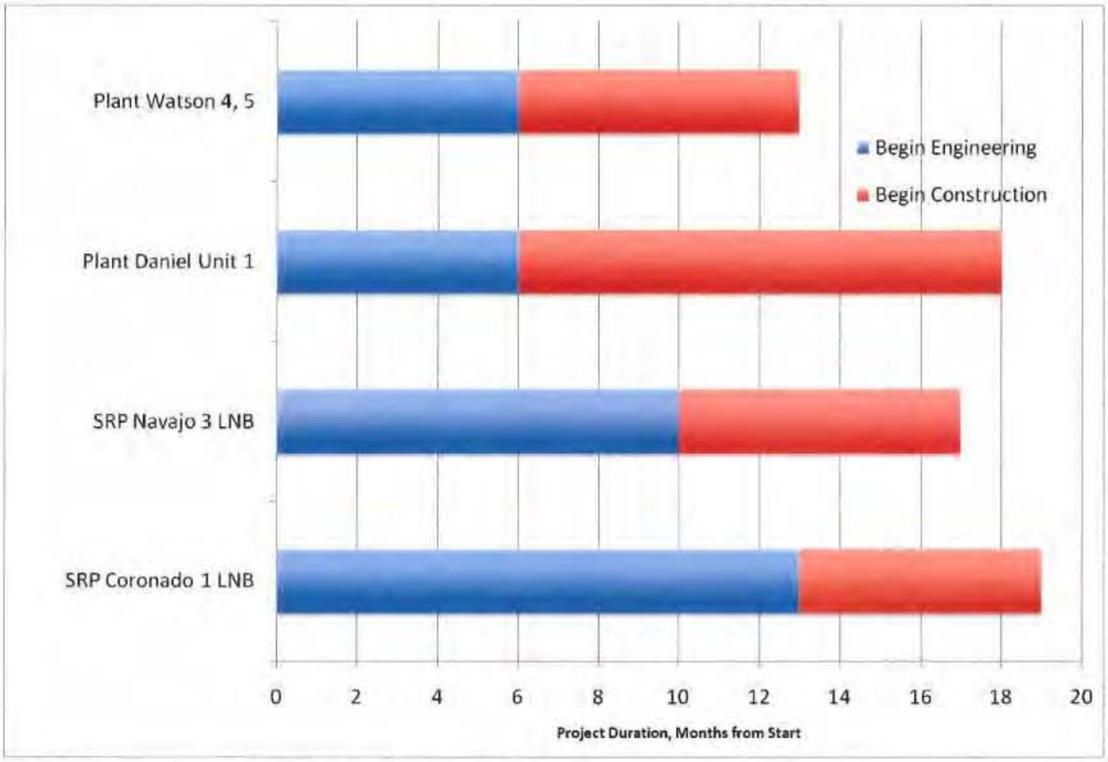

Figure 4-2. Timeline of NO_x Control Projects – LNB

4.1 SELECTIVE CATALYTIC REDUCTION (SCR)

The design and installation of SCR is considered for single unit retrofit and multiple projects at one site. This section of the report also treats SCR installation projects conducted contemporaneously with FGD. Unlike the case for FGD, the use of a single, modular process design is not a widespread practice. This is because the location of the SCR process – between the economizer outlet and air heater inlet – requires a tailored, site-specific treatment.

Figure 4-1 presents a summary timeline for representative SCR projects, depicting the start of engineering and procurement, and construction. Figure 4-1 shows a variety of project durations. The data show that there is only a minor effect as to whether an SCR process has been previously installed at a given station. This is because there is no central, shared facility of the magnitude of a reagent receiving and preparation system that can be expanded, or a byproduct management system, where an existing system can be exploited. There may in some cases be a benefit of exploiting the existing ammonia-based reagent preparation system, depending upon EPA's eventual regulatory determination of how such materials are to be classified.

4.1.1 INSTALLATION OF A SINGLE SCR UNIT AT A SITE

Several owners retrofitted a single SCR reactor to a site. Examples of such retrofits include the work done at Alabama Power's Barry Unit 5 (50 months) and Gaston Unit 5 (40 months), AEP's Conesville Unit 4 (42 months), CPS's J.T. Deeley Station (36 months), Duke's Marshall Unit 3 (46 months), Georgia Power's Hammond Unit 4 (28 months), and Gulf Power's Crist Unit 7 (42 months). Selected units are further described as follows.

Georgia Power Plant Hammond (28 months). Georgia Power's Plant Hammond Unit 4 represented the shortest schedule of any unit retrofit by this owner. Several reasons contributed to an installation schedule that was markedly shorter than others undertaken recently. First, Unit 4 is an end unit – thus construction could proceed during routine operation, as access to the reactor was adequate. Also, the unit required minimal modifications to the gas handling system. These benefits to schedule did come at a price – two cranes (rather than one) were required, and the tie-in time due to extended ductwork was closer to 7 weeks and not the typical 4 weeks.

Alabama Power Gaston Unit 5 (40 months). Alabama Gaston Unit 5 required 40 months, one of the longest project durations experienced by this owner. Most notably, major modifications to the gas handling system were necessary to accommodate the change in gas pressure drop; in addition to new fans both structural and electrical infrastructure had to be improved. The extremely congested site, adjacent to a river, minimized site access for construction, requiring mostly costly crane and protracted erection procedures. Ductwork location was complicated by coal conveyors, and the need for foundations in limited space. Finally, the altered ductwork arrangement required a new breach to the stack, imposing complexity.

Duke Energy Marshall Unit 3 (46 months). It took approximately 12 months of upfront work at this site before the contractor was given authorization to proceed with detailed engineering. When the time for these efforts is added to the time needed for actual construction, the total time for this installation is 46 months.

In summary, for cases involving the retrofit of a single SCR reactor at a site, the construction schedule will depend on the specific characteristics of the site, including technical details of the application, and the engineering prep work. Recent examples of the installation of a single SCR unit indicate that it takes between a total of 28 months and 50 months (an average of about 40 months) to complete such projects.

4.1.2 MULTIPLE SCR PROCESSES AT ONE SITE

There are several examples of plant owners retrofitting multiple processes for the control of NO_x at one site. Sites at which multiple SCR units have been installed include First Energy's Sammis Plant (retrofits on Units 6 and 7 required a total of 60-62 months); Alabama Power's Miller Station (where retrofits on Units 1 and 2 each took a total of 42 months and retrofits on Units 3 and 4 each took a total of 34 months); AEP's Kyger Creek Plant (where there was a retrofit of 5 SCR units, with the first operable within 31 months); Progress Energy Crystal River Station (where SCR retrofits on Units 4 and 5 took 37 months); and Georgia Power's Scherer station project (which includes work on SCR for Units 1 through 4, and where the SCR system closest to completion is that for Unit 3, which is scheduled to be completed in a total of 50 months). Also worth mentioning is Associated Electric Cooperative's work to control NO_x at its Thomas Hill Station (including the addition of an SCR system and low NO_x burners on Unit 3 and work on the Unit 2 SCR).

The collective experience for this class of project suggests that it takes between 31 and 50 months (an average of approximately 44 months) to install the first of multiple SCR systems at a site and subsequent units come on after varying intervals, depending upon site-specific factors. It can, however, take much longer than the "average" time to complete SCR installations, as demonstrated by the experience at the Sammis site. Further details of selected stations are described as follows:

First Energy Sammis Units 6 and 7. Sammis 6 and 7 required approximately 60-62 months from the start of engineering to process startup. Section 3 discussed the difficulties encountered for FGD, and Figure 3-2 presented a pictorial view of the station. The SCR units were installed in an extremely congested environment. The retrofit of SCR to Units 6 and 7 required significant equipment demolition; the original equipment ESPs that had been decommissioned and abandoned in place (as new, upgraded particulate control equipment was installed) had to be removed. The ESPs occupied the space that was the only option for locating the SCR reactors.

The constrained site as shown in Figure 3-2 illustrates that the significant demolition and equipment relocation are primary reasons why 60-62 months was incurred.

Kyger Creek. AEP retrofit five SCR reactors to the Kyger Creek Station in a period of approximately 31 months. The number of identical units and the generating capacity were key to achieving this abbreviated time: all five units are identical so engineering could be expedited, and the modest generating capacity (220 MW per unit) did not require large quantities of material to be installed or relocated. The use of cranes within the compact site, and small distances over which to transfer materials also contributed to expeditious installation. Although the plant site is constrained, the units are small – and construction can be staged to address these in a serial manner. Consequently the 31 month period is not considered typical.

Georgia Power Scherer Unit 3. Unit 3 – the first unit to be operational at this site - is planned to be completed within about 50 months, with engineering and permitting commencing 19 months prior to any startup activities. Other units at Scherer that will receive SCR – Units 1, 2, and 4 – are scheduled for start up after Unit 3. The complexities of the site, and general congestion of executing these projects contemporaneously, extends the implementation schedule for these units. For example, Unit 4 is scheduled to be operable in early 2012, incurring a more than 60 month project schedule, about 10 months following Unit 3. Units 1 and 2 will be implemented after Unit 4 by a similar amount of time.

4.2 LOW NO_X BURNERS

The reduced complexity of an LNB system, compared to an SCR or FGD process, does not necessarily translate into abbreviated permitting procedures. As with SCR, construction schedules for LNB installations will depend on conditions at the specific site, including details of the application, the engineering and unit preparation work, and the availability of an outage. Most notably, a key factor in determining the installation schedule is the availability of LNB equipment. The limited number of qualified suppliers, and the special-purpose fabrication techniques required, can extend fabrication and delivery times. Also, there can be complications in the permitting process. At least one multi-state owner is anticipating a lengthier schedule for installing LNB equipment, due to concerns that have arisen in the permitting of the installations, where local regulatory agencies are questioning whether lower NO_x emissions are inextricability linked to higher CO emissions. Regardless of whether or not there is any validity to the claim, that permitting process is anticipated to be time consuming.

Figure 4-2 presents schedule information provided for low NO_x burners at Salt River Project's Coronado Unit 1 and Navajo Unit 3. Also included in Figure 4-2 is a schedule typical of LNB retrofits in the Southern Company System (based on recent LNB retrofits to generating units at Plants Daniel and Watson). This experience suggests project installations typically take a total of about 18 months.

Not included in Figure 4-2 is information on LNB installations for two 760 MW units (Units 4 and 5) at Progress Energy's Crystal River facility. The LNB installations were part of a larger project that took many years to complete and that included installation of an SCR unit, an FGD system, and an acid mist mitigation system (ammonia injection) and significant upgrades to the precipitator. If the low NO_x burners had been installed on their own, company representatives estimate that permitting and construction would have taken 18 to 24 months.

The Crystal River installations are addressed here, though, because they are an example of a relatively straight-forward LNB installation project. LNB retrofits can take less time than on average if (as Progress could do at Crystal River) companies can use "plug-in" burners that require minimal pressure-part changes. In many cases, though, more significant modifications are required – the burner "throat" may have to be expanded, to lower gas velocities and control mixing of fuel and air. Increasing the size of the penetration in the furnace wall to accommodate an enlarged burner throat will require high pressure part modifications. Further, the use of "overfire" or secondary air ports may be required to promote burner performance – these ports will also require pressure-part modifications, and increase installation times. For these latter conditions, 18-month project schedules are typical.

SECTION 5

CRITIQUE OF EXAMPLES CITED BY EPA

This section of the report responds to – and offers additional information on – retrofit examples that EPA has cited in support of its idea that it is reasonable to expect a single FGD installation to be completed in a total of 27 months and a single SCR installation to be completed in a total of 21 months. As noted in the following sections of this report, the installations cited by EPA (EPA, 2005; EPA, 2002) in support of those shorter installation schedules occurred at the beginning of the last decade and are not representative of recently completed FGD and SCR installations, or of FGD and SCR retrofits that are likely to be undertaken in the near future. There are many reasons for this, including the fact that first generation installations took place before owners and contractors knew all the pitfalls presented by these kinds of projects; now that the pitfalls are better known, plant owners typically require more up-front work on equipment design and engineering. They want to "get it right," rather than just taking it on faith that contractors will know how to address the unique factors presented by each installation.

Also, EPA's handful of examples fails to capture the variety of conditions one can expect to find at all the sites now being evaluated for control equipment retrofits. The wide distribution of implementation schedules displayed in Figures 3-1 and 4-1 bears witness to the fact that each site is unique and each presents its own retrofit challenges.

Finally, as discussed below, previous descriptions of the projects cited by EPA in support of its short installation deadlines may be incomplete. Additional information suggests that, in fact, some of the projects cited by EPA took longer to complete than suggested by EPA.

5.1 FGD INSTALLATIONS – OVERVIEW

Figure 5-1 is a timeline showing the amount of FGD capacity that has been installed over the past decade and that is anticipated to be installed in the next two years. The figure shows that the demand for FGD equipment – and although not shown, SCR equipment – was low around the year 2000, the time when all four key references cited by EPA were implemented. This figure suggests the experiences of those undertaking FGD retrofits at the beginning of the past decade may not be representative of the experiences of those contemplating and conducting FGD retrofit at present. Further details concerning the EPA-cited retrofits that were undertaken approximately 10 years ago are described in the following sections.

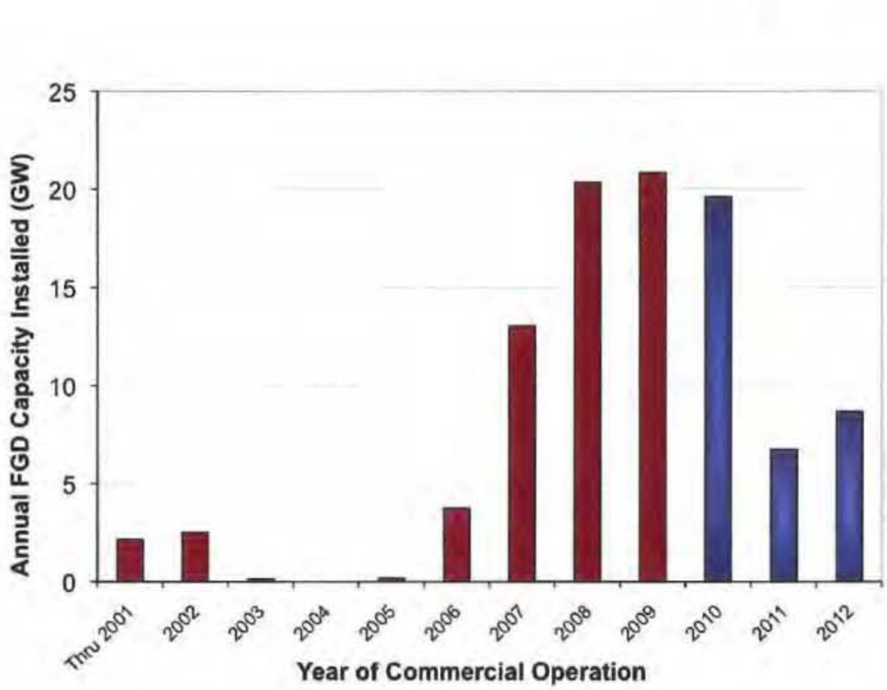

Figure 5-1: Timeline Showing Recent Installed FGD Capacity by Startup Date

5.2 EPA EXAMPLES OF FGD INSTALLATIONS BEING COMPLETED IN A TOTAL OF LESS THAN 30 MONTHS

EPA cites two examples of FGD installations being completed in a total of less than 30 months: those at Centralia and Tampa Electric Company's Big Bend Station. Further information on those installations is provided below.

5.2.1 CENTRALIA WET FGD

The Centralia FGD project was completed in November 2001. EPA claims that it was completed in less than 30 months. In fact, the complete installation process appears to have taken longer than 30 months. Based on information in the public domain (Miller, 2004), it appears that Centralia owners first initiated engineering for wet FGD for their units in January of 1999, not in May 1999 (as was previously reported), that FGD performance tests for the first unit were conducted in November of 2001, and that the unit was declared commercial in December of 2001. Given that the installation of process equipment is not declared to be "substantially complete" until performance tests indicate the unit can be accepted for operation, this information indicates that it took a total of almost three years to do all the work to install the FGD system for Unit 1 at Centralia. In addition, the reported on-line date for Unit 2 (December 2002), indicates that 48 months were required for completion of work on the second Centralia unit.

In addition to the fact that the Centralia installation appears to have taken more than a total of 27 months to complete, there are reasons to believe that the Centralia installation is atypical. As noted in comments being separately submitted by Southern Company, the contract for the engineering and construction work at Centralia was part of a unique "partnering" agreement between the owners of Centralia and the contractor. This type of relationship can speed subcontracting and procurement activities, but it can also require significant upfront negotiations and arrangements. As noted above, however, there can be pitfalls to any approach that does not set aside adequate time prior to the start of construction to ensure that the project design and engineering are done right.

Also, because Centralia was an early generation installation, the plant owners may have had access to a larger number of experienced craftsmen to work on the project than would be available today, when so many retrofits are being implemented in the same time period. Moreover, as an early generation retrofit, Centralia may have faced fewer permitting obstacles than are faced by those now seeking to retrofit FGD units (see Section 2.2.5 of this report).

Finally, it appears that the Centralia site was not as challenging a candidate for retrofits as some of the sites described in Section 3 of this report.[5]

5.2.2 TAMPA ELECTRIC BIG BEND

Tampa Electric Company's installation of FGD systems on Big Bend Units 1 and 2 was also an early generation project. Starting with time to prepare a detailed FGD bid specification, it first appears (based on reports in the technical literature) that this project was operational in about 28 months. (Smolenski, 1999.) However, further investigation reveals that the reported schedule does not take into account that Tampa Electric conducted preliminary cost assessments and prepared the FGD procurement specification 8 months earlier. Also, a further review of records shows that the permit application for the project was submitted in July of 1996. This all indicates that the total amount of time needed to design, permit, and construct the FGD system was closer to a 42 month schedule than a 27- or 28-month schedule.

In addition, there are several reasons for believing this project is not representative of the situations faced by many of the companies that will have to retrofit FGD units in the next five years. For example, it was possible for TECO to truncate the installation schedule at Big Bend by building upon the FGD installations that were already located at the site and in use at Big Bend Units 3 and 4. The reagent receiving and processing equipment and dewatering apparatus for the FGD equipment on Units 3 and 4 could – with some limited modification – be used in the new FGD installations at Units 1 and 2. Also, the land use permit for solid byproduct management already existed at Big Bend and likely received less scrutiny, which is

[5] An indication of the fact that the Centralia retrofit may not have been a challenging one is that the reported FGD retrofit cost of the project (approximately \$100/kW on a 2001 dollar basis and \$150/kW on a 2010 dollar basis) are a factor of 2-3 less than more recent projects.

very different from the situation faced today by those seeking permits for new, "greenfield" byproduct management sites.[6]

5.3 EPA EXAMPLES OF SCR INSTALLATIONS BEING COMPLETED IN A TOTAL OF LESS THAN 30 MONTHS

EPA cites two examples of SCR installations being completed in a total of less than 24 months: those early 2000 installations at the AES Kintigh station in New York and Reliant Energy's (now NRG's) Keystone station in Pennsylvania.

No information is available in the literature concerning the SCR project for Keystone, and very little information is available concerning the SCR project at the AES Kintigh station in New York. The available data do suggest, though, that the Kintigh project – from start to finish 9 months in duration, and one of the first SCR retrofit installations in the country – is atypical in several respects. For example, the procurement process for the Kintigh project does not reflect what most plant owners would have to follow today: there is no evidence this work was competitively bid; indeed, it is possible that B&W was the contractor selected because B&W provided the boiler and plant ancillary components. This "non-traditional" approach to selecting a contractor – perhaps not unreasonable for the time period – bypassed the open, competitive bid process generally mandated for an investor-owned utility or public agency. This procedure may not be available to investor owned or public agencies without prudency challenges.

Also, the non-traditional Kintigh facility approach generally does not make sense for the much more complicated installations that companies now face. More complex projects require more effort to be taken up-front in the planning process – before actual construction begins – in order to minimize problems on the back end. Further, as noted in Section 2, those involved in the Kintigh project faced far fewer regulatory obstacles 10 years ago than plant owners face today. For example, a decade ago, companies did not have to deal with current requirements to predict and mitigate SO_3 emissions from SCR units.

5.4 OTHER FACTORS

EPA also acknowledges (EPA, 2005; EPA, 2002) that the installation of multiple FGD and/or SCR units at one site will require more time than suggested in the proposed transport rule proceeding. While the overall conclusion is correct – installing multiple control units at one site will take longer than installing just one control unit at the site – EPA underestimates the complications in undertaking multiple installations simultaneously at a site. EPA assumes that many of the basic activities required – conceptual system design, selecting the precise technology to be installed, developing technical specifications for the project, identifying bidders,

[6] As was the case with the Centralia retrofit, a further indication that the Big Bend Unit 1 and 2 FGD retrofit may not have been a challenging one is that the reported FGD retrofit cost of the project was low: approximately $100/kW on a 2001 dollar basis.

procuring their bids, evaluating those bids, and awarding contracts – are executed for not one but multiple units[7]. However, the rate-limiting step in a multi-project FGD or SCR retrofit is usually construction, and the impediments that retrofit activities for one unit can impose upon another. It is optimistic for EPA to assume that the incremental required time period for each additional retrofit would be just 4 months.

In summary, there is not sufficient information to be able to determine the actual time it took to design, permit, and construct the projects upon which EPA relies in concluding that FGD and SCR retrofits can routinely be completed in a total of less than 30 months. There is, though, a long list of reasons why the FGD and SCR retrofits undertaken a decade ago may have taken less time to complete than those now being undertaken. It is generally believed the first generation of retrofits provided fewer challenges to those presently undertaking the work. For example, the simpler sites were logically chosen first. Also, in the present timeframe, there are difficulties in getting necessary preconstruction permits now that did not exist (or did not exist to the current extent) a decade ago. And finally, even EPA acknowledges that multiple installations of FGD and SCR installations at a single site will take longer – sometimes much longer – than single retrofits. (Specifically, EPA concluded five years ago that it would then take 30 to 40 months to install multiple SCR and FGD equipment, respectively (EPA, 2005).) All of these factors undercut EPA's current conclusion (set out in the preamble of the Proposed Transport Rule) that FGD and SCR retrofit installations can typically be completed in a total of less than 30 months.

[7] See Figures 1 and 2 of EPA, 2005.

SECTION 6

SUMMARY/CONCLUSIONS

Significant evidence exists to show that the installation schedule proposed by EPA for SCR and FGD process equipment – 21 and 27 months, respectively – is unrealistic. Actual installation schedules that are reported in Sections 3 and 4 significantly exceed EPA's projections.

Table 6-1 summarizes the observed total schedules for design and installation of flue gas desulfurization, selective catalytic reduction, and combustion controls (e.g., low NO_x burners).

Table 6-1. Summary of Design, Fabrication, Installation Period

Control Technology	Site and Application Category	Design, Fabrication, Installation (Months)
Flue Gas Desulfurization	Single Unit to Station: Large Owner	48
	Single Unit to Small (e.g., Cooperative) Owner	50
	Two Units to Site	51
	Three or More Units to Site	54
Selective Catalytic Reduction	Single Unit to Site	40
	Multiple Units to Site	44
Combustion Controls	Both single and multiple installations	12-18 months, depending on the specific conditions

As noted in both Sections 3 and 4, despite attempts to solicit schedule information from a representative sample of owners, it is not known if the results described in this report reflect a true statistically representative sample. As a consequence, although the estimates presented in Table 6-1 are believed valid, the trends between different categories should be viewed as approximate. However, it should also be noted that the number of example cases cited – for FGD (23 projects at 21 stations), and for SCR (15 projects at 13 stations) – well exceed the much smaller number of references cited by the EPA.

The few cases cites by EPA provide no legitimate basis for challenging the reasonableness of the schedules cited in Table 6-1. As noted in Section 5, the cases upon which EPA relies were done almost a decade ago and represent less than 5% of the present FGD and SCR inventory which has been installed. The evolution of the degree of sophistication of technology, permitting requirements, and market forces since that time has evolved as follows:

6.1 DEMAND

The demand for competent process design and equipment suppliers will lengthen schedules. The reference cases were selected from a period when less than 5% of the existing inventory was installed. Having such an abundant talent pool may have allowed construction schedules to be compressed during that timeframe. That is not possible now, when there is much greater demand for competent process design and equipment suppliers.

6.2 LABOR PRODUCTIVITY

Demand affects labor productivity: with scores of projects underway simultaneously, there will be much more demand for the limited pool of skilled workers. As discussed in Section 2, this can have a disproportionately adverse effect on later-in-the-pipeline projects, which can frequently be projects for smaller utility systems. Construction schedules can be protracted as work schedules cannot be accomplished quickly with less experienced staff.

6.3 ENGINEERING

McCarthy (2004) describes a typical effort required a two-phase engineering approach, independent of whether a company adopts a system design or an individual optimized design. The first phase established the design basis (gas flow rate, gas composition, available reagent composition), optimized a standard absorber design, established balance-of-plant needs, and developed a layout and preliminary cost. The second phase addressed details of balance-of-plant and auxiliary equipment, and developed detailed contracts for fabrication and construction schedules by which to manage the work and hold subcontractors accountable. Each phase reportedly required 6 months. Such attention to detailed design is necessary, for either approach that emphasizes a system versus an optimized individual unit design. Before awarding contracts valued at several hundred million dollars, any less effort in the present activist climate could invite prudency challenges.

6.4 PERMITTING

As discussed in Section 2.2.5 of this report, those retrofitting SCR and FGD installations today face far more regulatory hurdles today than plant owners faced 10 years ago or even 5 years ago. For example, the court's vacatur of the "pollution control project exclusion" provision means that projects to install SCR and FGD units can be subject to the rigors of the new source review preconstruction permitting program. Also, those retrofitting SCR units will need to conduct a detailed estimation and accounting of byproduct sulfuric acid emissions, with remedial means included in the design. These permitting issues were assuredly not part of the 9-month SCR retrofit at the Kintigh facility. In addition, as also discussed in Section 2.2.5, those undertaking FGD retrofits will face myriad other requirements to get environmental permits (some of which could take 4 or more years to get) and other authorizations .

SECTION 7

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Smolenski, 1999	Smolenski, J., et al., 'Tampa Electric Company Phase II FGD System Big Bend Station Units 1 & 2 Advanced Design – Low Cost", Proceedings of the EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium: The Mega-Symposium, August 16-20, 1999, Atlanta, GA.
Wall, 2010	Wall, D., et al., "Implementation Strategies for Southern Company FGD Projects", proceedings of the 2010 Mega-Symposium, August 30-September 2, 2010, Baltimore, MD.

Attachment II

J. Marchetti, E. Cichanowicz, and M. Hein, "Schedule of Control Technology Retrofit To Meet EPA's Proposed Transport Rule" (Oct. 1, 2010).

SCHEDULE OF CONTROL TECHNOLOGY RETROFIT TO MEET EPA'S PROPOSED TRANSPORT RULE

Final Prepared By

James Marchetti
J. Edward Cichanowicz
Michael Hein

October 1, 2010

TABLE OF CONTENTS

SECTION 1 INTRODUCTION 1-1

SECTION 2 EVALUATION METHODOLOGY 2-1

SECTION 3 REVIEW OF 2008-2010 CONTROL TECHNOLOGY RETROFIT EXPERIENCE 3-1

3.1 GENERATING CAPACITY RETROFIT 3-1

3.2 BOILERMAKER HOURS 3-1

SECTION 4 CRITIQUE OF EPA'S APPROACH TO DETERMINING REQUIRED FGD AND SCR CAPACITY 4-1

SECTION 5 REVISED SCHEDULES AND MODELING RESULTS 5-1

5.1 SCHEDULE FOR INSTALLING FGD AND SCR 5-1

5.2 DETERMINING THE SCHEDULE 5-1

5.2.1 Owner-Announced Project Dates 5-2

5.2.2 Modeled Project Start Dates 5-2

5.3 REQUIRED BOILERMAKER HOURS 5-3

SECTION 6 OBSERVATIONS 6-1

LIST OF FIGURES

Figure 3-1. FGD Capacity Installed: 2008-2010 3-2

Figure 3-2. SCR Capacity Installed: 2008-2010 3-2

Figure 3-3. Relationship between Required Boilermaker Hours for FGD and SCR Installation and Generating Capacity 3-3

Figure 3-4. Calculated Boilermaker Demand for Both FGD and SCR: 3Q 2006 though 2Q 2010 3-4

Figure 4-1. EPA New FGD Capacity Base and Limited Trading Cases 4-2

Figure 4-2. EPA New SCR Capacity – Base and Limited Trading Cases 4-2

Figure 4-3. EPA Estimate of the Number of FGD and SCR Projects Operational: 2011 to 2014 4-3

Figure 5-1. Predicted FGD and SCR Operational Dates for Inventory of PTR-Affected Units 5-3

Figure 5-2. Quarterly Demand for Boilermaker Hours: Predicted PTR Compliance (FGD and SCR) 5-4

Figure 5-3. Quarterly Demand for Boilermaker Hours: EPA-Assumed Project Schedules (FGD and SCR) 5-5

LIST OF TABLES

Table 5-1. Estimated Implementation Schedule (Months) For FGD, SCR Projects...... 5-2

SECTION 1

INTRODUCTION

The Environmental Protection Agency on August 2, 2010, published the Proposed Transport Rule (PTR), the anticipated replacement of the Clean Air Interstate Rule (CAIR). The EPA in the August 2 announcement provided background support material, including analyses that assigned allocations of permissible levels of SO_2 and NO_x emissions to owners of electric generating units (EGUs). EPA in the background support material projected a total of 159 EGUs would retrofit a total of 185 control technology projects[1], on a total generating capacity approximately 14 GW[2], to meet this mandate.

The EPA projected a two-phase compliance schedule that purportedly describes how industry will deploy control technology – by January 1, 2012, and January 1, 2014. This compliance schedule was determined by EPA staff using IPM. The EPA-projected compliance schedule predicts that all 185 retrofit projects proposed for the 14 GW of generating capacity will be operational by January 1, 2014. Consequently, EPA does not expect compliance delays.

A key assumption inherent to EPA's results is that advanced control technologies – flue gas desulfurization (FGD) for SO_2 and selective catalytic reduction (SCR) for NO_x – can be installed in timeframes that, by recent industry experience, are abbreviated and unrealistic. Specifically, EPA assumes that SCR and FGD can be implemented in time spans of 21 to 27 months, respectively. EPA expects that, within these time spans, utilities will complete all project elements – from project conception to successful commercial operation. The adequacy of these 21- and 27-month periods has been challenged and is the subject of a companion report submitted with the comments of the Utility Air Regulatory Group.[3] In contrast to EPA's projected periods of 21 and 27 months, UARG submits documented experience that shows the reference cases selected by EPA from which to judge timeframes are not representative of present-day utility experience. Actual implementation dates are much longer.

This report projects a compliance schedule that is realistic and based on actual industry experience. The results show the requisite generating capacity cannot be retrofit by the EPA-required deadline. The inability to deploy the control

[1] See EPA parsed files at http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html

[2] 75 Fed. Reg. at 45273 (Aug. 2, 2010).

[3] Implementation Schedules for Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Process Equipment, Utility Air Regulatory Group, October 1, 2010.

technologies in a timely manner – due to a "logjam" of engineering, permitting, and construction activities – will compromise industry's ability to meet PTR mandates.

Section 2 presents an overview of the methodology used to project the schedule. Section 3 presents an analysis of the recently completed and on-going activities to retrofit FGD and SCR beginning in 2008 and through this calendar year. Section 4 critiques EPA's approach to projecting the compliance schedule. Section 5 presents revised results using realistic schedule assumptions. Section 6 offers observations on the results of the analysis.

SECTION 2

EVALUATION METHODOLOGY

This section presents an overview of the methodology taken to conduct this analysis.

First, EPA predictions of the number of units required to retrofit control technology were reviewed. EPA identified specific units that would likely adopt control technology[4]. This "inventory" of control technology candidates as described in EPA's "parsed" output files totals 185 projects, to be retrofit on 159 generating units. Specifically, EPA predicts that 106 units will retrofit FGD, 27 units will retrofit SCR. Of this inventory of units retrofitting control technology, a total of 26 units will retrofit both SCR and FGD.

Second, a realistic schedule for project implementation based on the companion report prepared for UARG's comments was identified. Specifically, an array of implementation schedules was identified based on the existing condition at the EGU (e.g., the unit's size and whether it already has FGD or SCR on one or more sister units at the power plant), and the number of units to be retrofit.

Third, those EGU's for which the unit owner or owners have an announced intent to install either FGD or SCR, or both, and an operating date for the control equipment, were identified. This pool of units was assigned the respective operating dates as identified by their owners. These units were treated differently than the inventory that EPA identified as candidates for control installation.

Fourth, the inventory of units for which the owner did <u>not</u> assign specific operating dates was assumed to start installation in the third quarter of 2011. An EGU owner could not reasonably begin a project earlier than this date, in light of EPA's announced plan to complete this rulemaking in June 2011. (Even this third-quarter 2011 date does not allow time for states to propose and make final SIP revisions to implement the final rule and obtain EPA's approval of SIP revisions.)

Fifth, the project operating dates were determined based on (1) the assumed start date and the applicable project implementation schedules or (2) the owner-announced operating date, in the case of those units with owner-announced operating dates.

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[4] EPA parsed files at http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html

Sixth, the boilermaker labor-hours demand for the projected 2012 to 2014 PTR compliance was determined and compared to the historical demand for the 2008-2010 FGD installation period (which is reviewed in Section 3 of this report). The boilermaker demand that would be necessary based on a realistic compliance schedule – with installations extending beyond EPA's assumed January 2014 operating date as necessary to reflect those realistic schedules – was calculated and compared to the 2008-2010 historical demand. The boilermaker demand that would be necessary for the unrealistically accelerated deployment that would be required to meet EPA's schedule – using an assumed January 2014 operating date (and ignoring the real-world installation schedules described in this report and the companion report) – was calculated and compared to the historical 2008-2010 value.

SECTION 3

REVIEW OF 2008-2010 CONTROL TECHNOLOGY RETROFIT EXPERIENCE

This section reviews the utility industry's 2008-2010 experience in retrofitting both FGD and SCR, and describes how this experience is invoked to project implementation schedules for 2012 to 2014. Both the generating capacity retrofit and the demand on boilermaker hours are considered.

3.1 GENERATING CAPACITY RETROFIT

Figures 3-1 and 3-2 illustrate the FGD and SCR capacity that was installed during 2008 and through the end of 2010.[5] Figure 3-1 shows that more than 20,000 MW of FGD capacity came on-line in each of 2008 and 2009, and more than 15,000 MW of capacity is anticipated to be operational in 2010.

Figure 3-2 presents the installed generating capacity of SCR over the similar period. Figure 3-2 shows that although the generating capacity of SCR installed is small compared to FGD, it is a significant amount on an absolute basis.

3.2 BOILERMAKER HOURS

The inventory of FGD and SCR equipment installed in 2008 and 2010 can be used to estimate boilermaker hours (i.e., person-hours of skilled boilermaker labor) needed for each incremental megawatt capacity of FGD or SCR retrofit.

The relationship between boilermaker hours demand and generating capacity, for both FGD and SCR, is shown in Figure 3-3. This relationship was developed based on discussions with suppliers, architect/engineering firms, and owners of EGU's that have implemented control technologies.

The relationship in Figure 3-3 is important in generalizing the experience in 2008-2010 and, based on that experience, projecting future boilermaker labor needs. Examining EPA's parsed output files shows that compared to the generating capacity of the units retrofit in 2008-2010, the generating capacity of units anticipated to be retrofit with FGD and SCR in 2012 to 2014 is smaller.

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[5] These data were estimated using the Emissions Economic Modeling System Data Base, which contains detailed data related to the electric utility sector, in terms of unit design, fuel, unit operation and production costs, installed control equipment, emission control assumptions and costs, and unit specific emission rates for over 2,500 steam electric units and all operating combustion turbine and combine-cycle units.

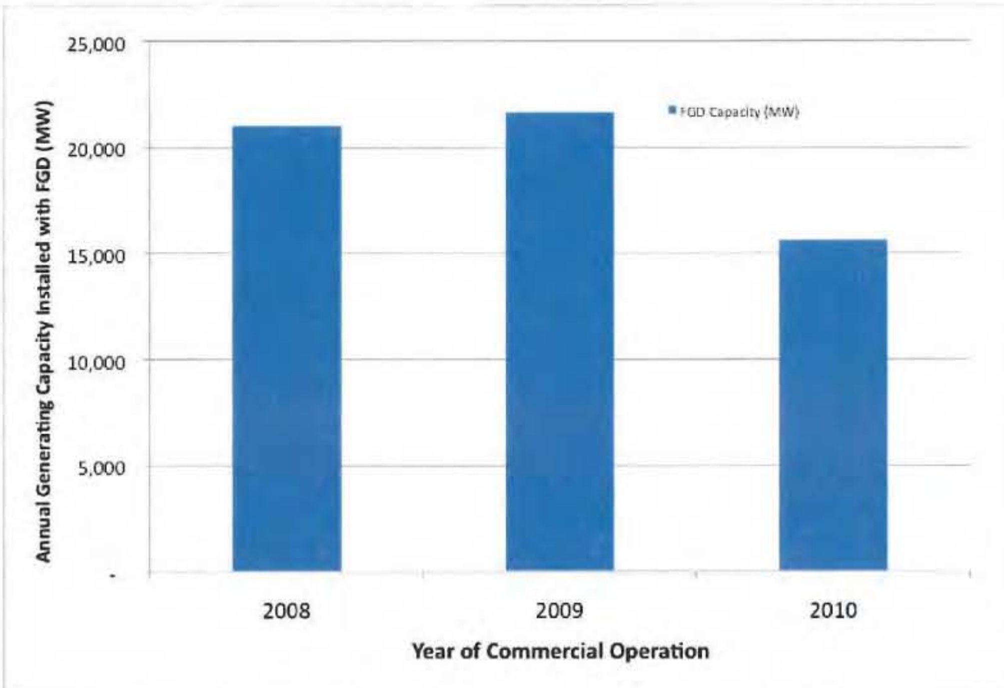

Figure 3-1. FGD Capacity Installed: 2008-2010

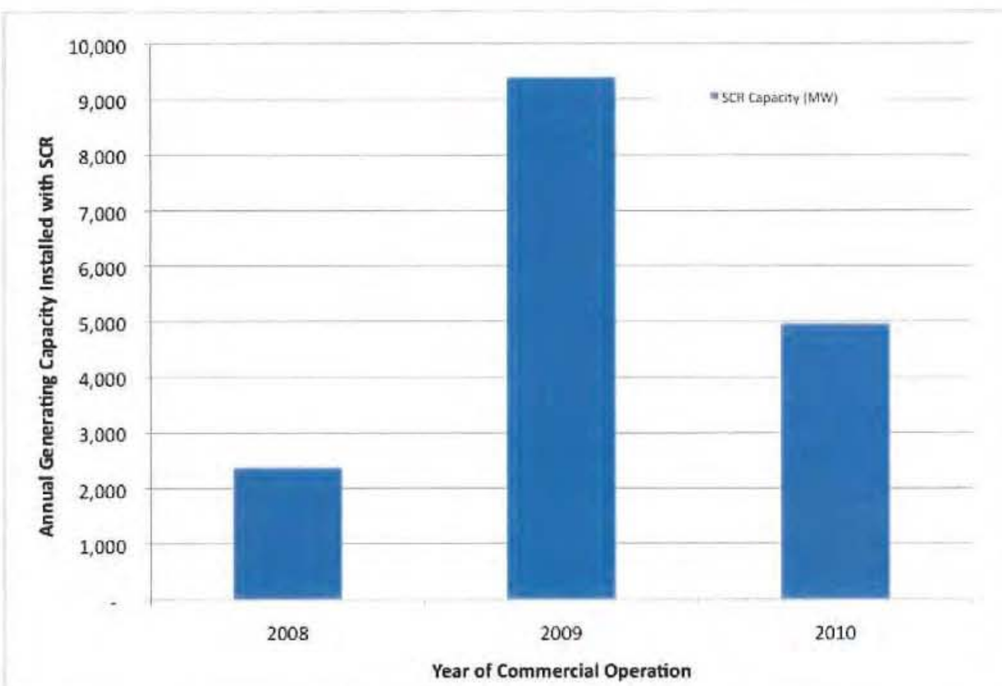

Figure 3-2. SCR Capacity Installed: 2008-2010

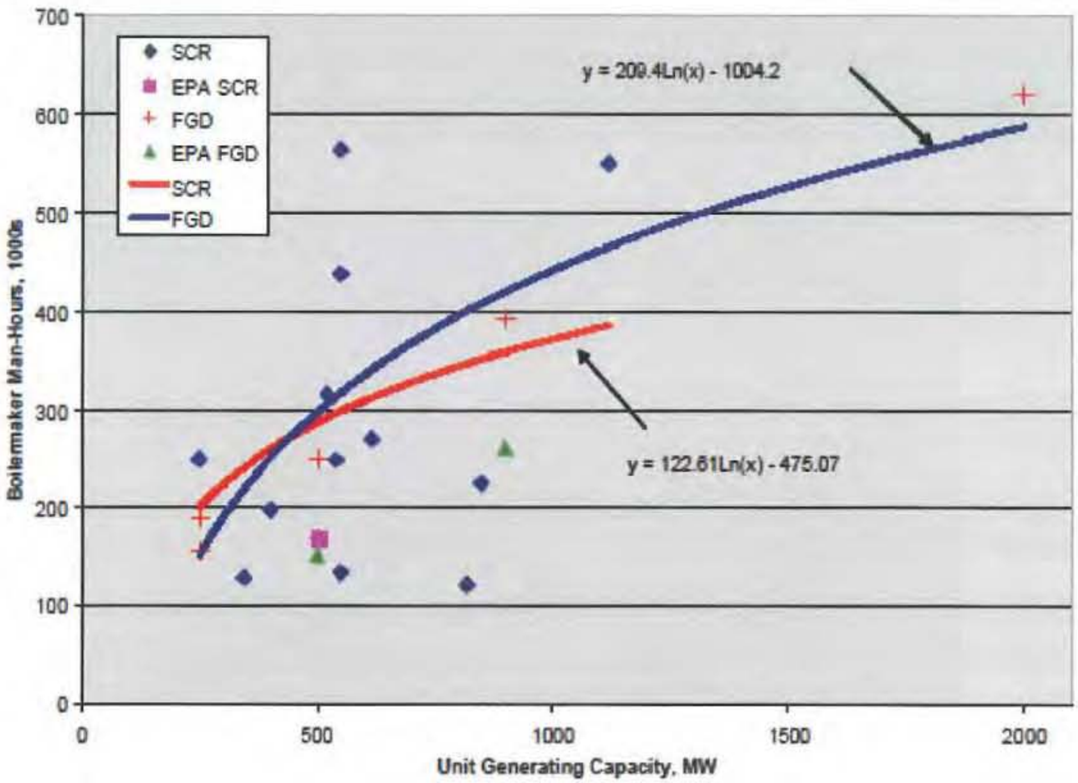

Figure 3-3. Relationship between Required Boilermaker Hours for FGD and SCR Installation and Generating Capacity

The non-linear relationship of boilermaker hours required and generating capacity shown in Figure 3-3 suggests more boilermaker hours and other construction consumables will be needed for the 2012 to 2014 retrofits, compared to the 2008 to 2010 retrofits, for an equivalent amount of generating capacity.

Figure 3-3 describes the boilermaker demand total for the entire project. The distribution of boilermaker hours is not uniform over the construction period; specifically, early work such as clearing and preparing the site, concrete and foundation work, and general construction activities do not require boilermaker skills. Based on discussions with suppliers, architect/engineering firms, and owners of EGU's, a relationship has been developed that presumes most boilermaker work is conducted over 5 quarters for FGD and 4 quarters for SCR, staged according to a schedule that has this work concluding one full quarter prior to project completion. This schedule represents the average experience within the industry.

Figure 3-4 presents the results of calculations of quarterly demand of boilermaker hours, as experienced in 2008 through 2010, based on Figure 3-3. The bar chart in Figure 3-4 shows that boilermaker-hours demand, reported both on a quarter total and a three-quarter trailing average, peaked through the middle and towards the end of 2008. Using this analysis, it is estimated that a quarterly maximum total exceeding 5.5 million boilermaker hours, and a three-quarter trailing average exceeding 5.1 million boilermaker hours, were required.

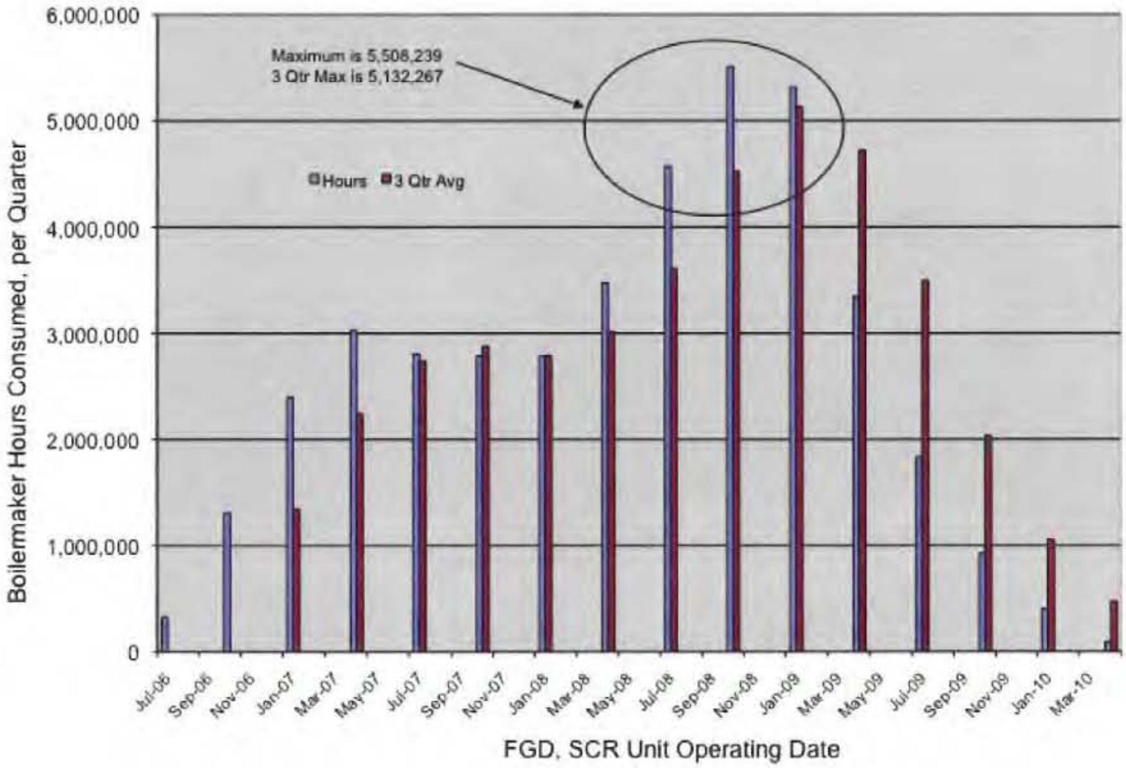

Figure 3-4. Calculated Boilermaker Demand for Both FGD and SCR: 3Q 2006 though 2Q 2010

The consumption of boilermaker hours in Figure 3-4 is assumed as a constraint on the construction of FGD and SCR in the 2012-2014 timeframe.

SECTION 4

CRITIQUE OF EPA'S APPROACH TO DETERMINING REQUIRED FGD AND SCR CAPACITY

The EPA analysis addressed two scenarios: (a) Base Case and (b) State Budget – Limited Trading. These two scenarios were evaluated to determine the number and generating capacity of FGD and SCR retrofits required for the years 2012 and 2014. It should be noted that Base Case compliance assumes compliance with other regulatory programs such as Title IV, NO_x SIP Call, Consent Decrees and State Programs, *but does not include any compliance with CAIR*. In EPA's preferred option (*State Budget – Limited Trading*), PTR allows for unrestricted intrastate trading and limited interstate trading among 32 states based upon state budgets.

EPA initially modeled the amount of "new" FGD and SCR capacity that would be required to meet the regulatory requirements of the Base Case in both 2012 and 2014. This modeled capacity is then carried forward into the Limited Trading Case, and is needed to meet the targets of the Limited Trading Case in both 2012 and 2014. (Note that the Limited Trading Case in 2012 includes FGD and SCR retrofits that EPA projects will be completed by 2012 in order to comply with the TR. Many of these retrofits were modeled by EPA; however, a few retrofits have been identified as retrofits that would have been installed to comply with CAIR or consent decrees.) With this Base Case capacity embedded, EPA then models the additional/incremental FGD and SCR capacity that would be required to meet the PTR's state budgets. Significantly, it should be noted that the FGD and SCR capacity predicted by EPA for the *State Budget – Limited Trading* scenario is incremental to that required for the Base Case capacity. Both Figures 4-1 and 4-2 illustrate the total amount of new FGD and SCR capacity, respectively, that will be required under the PTR by January 1, 2012, and January 1, 2014, including both the Base Case amounts (shown in blue) and the *State Budget – Limited Trading* Case (designated as "LT Case"), shown in red. (Note that the 2012 and 2014 amounts are not cumulative, i.e., the 2014 amounts do not include the 2012 amounts.)

Therefore, EPA's statement that the PTR will only result in 14 GW of additional FGD capacity by 2014 is misleading. As shown above, EPA omitted from the discussion the 10 GW of FGD capacity that will also be needed from the Base Case to achieve compliance under the Limited Trading Case by 2014. In reality, therefore, EPA has modeled, for completion after January 1, 2012, but before January 1, 2014, a total of approximately 25 GW of new FGD capacity and 8.2 GW of new SCR capacity in order to meet the PTR's targets.

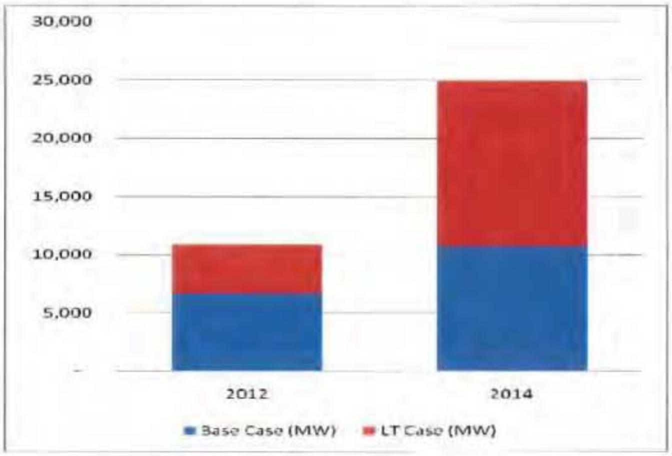

Figure 4-1. EPA New FGD Capacity – Base and Limited Trading Cases

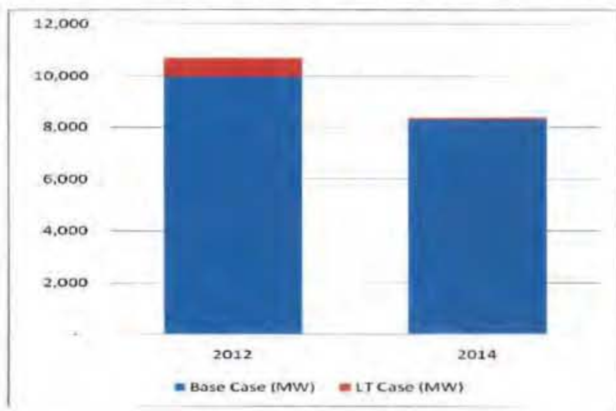

Figure 4-2. EPA New SCR Capacity – Base and Limited Trading Cases

Based upon EPA's estimated capacity for both 2012 and 2014, we have projected the number of new FGD and SCR retrofit projects by quarter. This identification of projects by quarter is displayed in Figure 4-3. The data in Figure 4-3 reflect EPA's assumptions that a given amount of capacity and generating units can be retrofit by 2012 and 2014. This depiction also shows that some of the owner-announced FGD and SCR projects will be operational at various times in 2013. It should be emphasized that the schedule shown in Figure 4-3, with the exception of the relatively modest number of projects (50) announced by EGU owners, is an assumption by EPA and not the result of a predictive analysis.

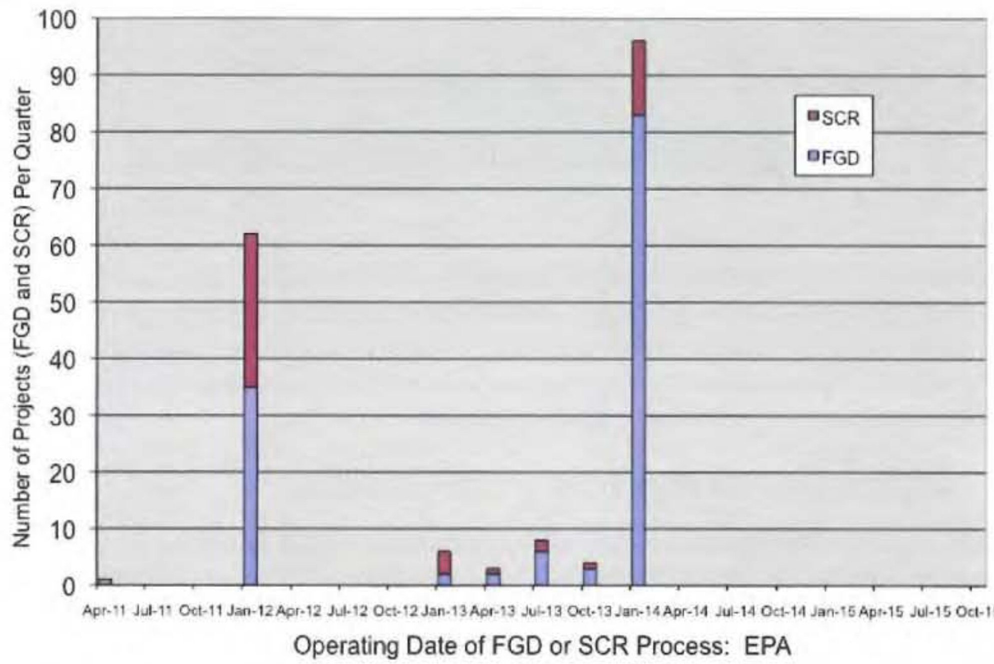

Figure 4-3. EPA Estimate of the Number of FGD and SCR Projects Operational: 2011 to 2014

SECTION 5

REVISED SCHEDULES AND MODELING RESULTS

This section presents a revised compliance schedule based on realistic assumptions of project implementation. Results presented in this section address (a) schedule assumptions for constructing and installing FGD and SCR process equipment, (b) the projected compliance dates based on a start date of the third quarter of 2011, and (c) the quarter-by-quarter boilermaker demand.

5.1 SCHEDULE FOR INSTALLING FGD AND SCR

Section 1 noted a companion report being submitted by UARG with respect to the PTR, summarizing realistic schedules for the retrofit of individual FGD and SCR process equipment. This analysis uses results from that document to project the compliance schedule for the inventory of units affected by the PTR.

Table 5-1 recommends FGD and SCR project retrofit schedules based on the UARG survey. The table summarizes the number of months required to implement an FGD or SCR retrofit project, starting with preliminary engineering or permitting, through commercial operation. The schedule data is presented for various categories of generating stations and conditions at the site – for example, the number of unit processes to be installed (i.e., the number of FGD modules or SCR reactors), and the existing equipment that is on-site. For both FGD and SCR, an abbreviated schedule is used for any unit for which an operating date has been announced by the owner. This special case presumes that EGU owners with announced operating dates have already initiated engineering, permitting, or other background activities. This assumption will not always be valid but is considered appropriate for these types of projects with owner-announced schedules.

These data were used to determine when a project would be operational, given a defined start date as described above.

5.2 DETERMINING THE SCHEDULE

The schedule by which the EGUs are predicted to have the control equipment installed and operational was determined. The EGUs predicted by EPA to install FGD and/or SCR were partitioned into two categories, and treated as described as follows:

Table 5-1. Estimated Implementation Schedule (Months) For FGD, SCR Projects

Control Technology	Site and Application Category	Design, Fabrication, Installation (Months)
Flue Gas Desulfurization	Single Unit at "Unscrubbed" Station: Large Owner	40
	Single Unit at "Unscrubbed" Station: Small (e.g., co-operative) Owner	45
	Single Unit at Site with Existing FGD Equipment	38
	Two Units at "Unscrubbed" Site	40 for first unit; second unit, additional 3 months
	Three or More Units at "Unscrubbed" Site	44 for first unit; additional units, additional 3 months each.
Selective Catalytic Reduction	Single Unit at Site	36
	Multiple Units at Site	39

5.2.1 Owner-Announced Project Dates

The scheduled retrofit of either FGD or SCR equipment (or both) has been announced by unit owners for 50 projects. This analysis adopted those dates without question. EGU owners for these projects released specific dates when the technology is planned to be operational. Some dates populate 2011; most are within the 2012-2013 timeframe.

5.2.2 Modeled Project Start Dates

All other units – i.e., all units besides the units with owner-announced dates – were considered to have start-project dates in 3Q 2011; these dates are accepted as the earliest dates an EGU owner could initiate engineering or permitting steps in light of EPA's planned rulemaking completion date for the PTR and the likelihood of changes to the PTR by the time EPA completes the rulemaking. Each retrofit project (FGD or SCR) was assigned an implementation timeline, based on the applicable unit category (per Table 5-1). This schedule, together with the assumed start date of 3Q 2011, defined the completion date for a given unit.

Figure 5-1 presents the project implementation as a function of time – defined by the quarter in which the FGD or SCR process becomes operational. Figure 5-2 shows that a 3Q 2011 start-project date, together with the applicable implementation timeline, results in a range of project completion dates under which only a fraction of projects can be operational by the EPA-proposed January 1, 2012, and January 1, 2014, compliance dates – and these projects are only those for which unit owners have announced a project completion date by January 1, 2012, or by January 1, 2014, respectively, and which this analysis assumes will meet their owner-announced completion dates. The largest number of FGD and SCR projects are projected to become operational (i.e., are completed) at various dates between early 2015 and mid 2016.

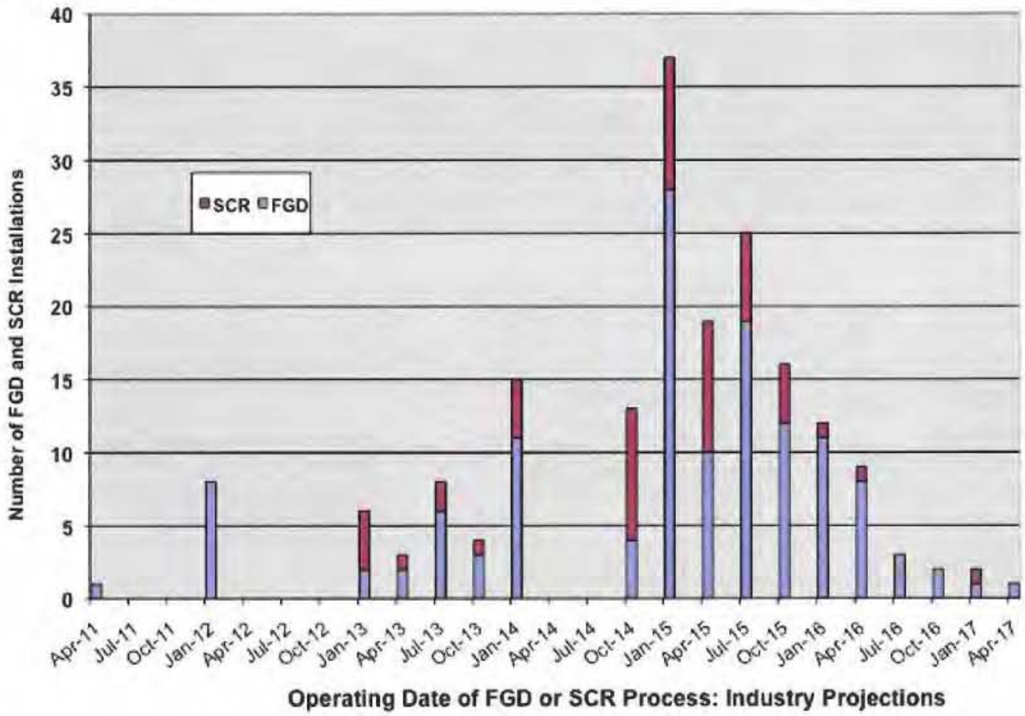

Figure 5-1. Predicted FGD and SCR Operational Dates for Inventory of PTR-Affected Units

The majority of units are projected to be unable to meet the EPA-proposed compliance dates; specifically, 54 projects targeting the January 2012 date are "late," while 81 projects targeting the January 2014 date are "late". Only about 27% of the targeted 185 retrofit projects are projected to meet the applicable EPA-proposed date.

5.3 REQUIRED BOILERMAKER HOURS

The project implementation schedule in Figure 5-1 can be used to calculate the demand for boilermaker hours for Transport Rule compliance.

Figure 5-2 presents the quarterly demand for boilermakers to support the PTR – but with the compliance schedule adjusted to reflect the more realistic control-implementation timetables as described and applied above. Under this scenario, the peak demand, for example, is projected to be somewhat more than 4,000,000 hours per quarter but less than the demand for the 2008-2010 FGD and SCR installation demand.

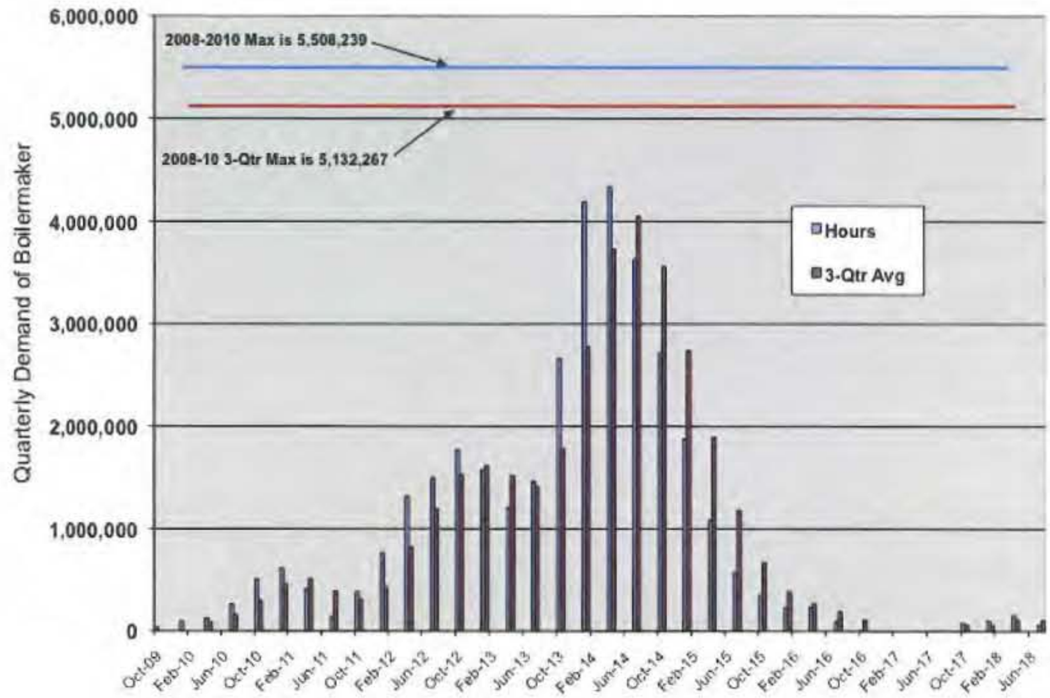

Figure 5-2. Quarterly Demand for Boilermaker Hours: Predicted PTR Compliance (FGD and SCR)

Separate from this analysis, the boilermaker demand was calculated to support the EPA-assumed project implementation schedule of 21 and 27 months, respectively, for SCR and FGD implementation. Figure 5-3 presents the results of this analysis. Figure 5-3 shows that, to meet EPA's proposed schedule, the estimated peak quarterly demand for boilermaker hours is approximately 8,000,000 hours and the estimated maximum three-quarter average demand is approximately 7,000,000 hours. Consequently, even if the engineering and permitting tasks could be completed and the necessary process equipment and material could be fabricated and delivered to the site – all within the 21- and 27-month periods EPA assumes and by the compliance dates it proposes – there would be no basis for concluding that a sufficient number of boilermakers would be available to do the work necessary to have the control equipment installed and operational within those periods.

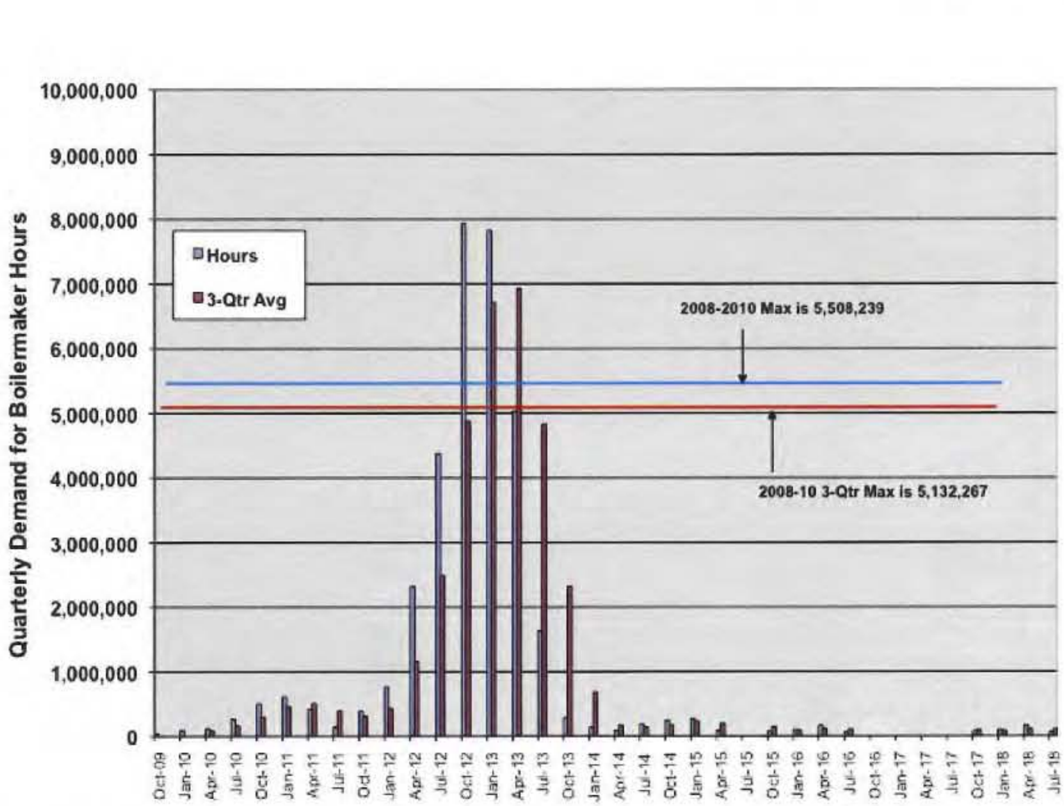

Figure 5-3. Quarterly Demand for Boilermaker Hours: EPA-Assumed Project Schedules (FGD and SCR)

SECTION 6

OBSERVATIONS

This report critically reviewed EPA assumptions regarding PTR implementation.

These results show that, contrary to EPA projections, there is inadequate time to deploy the necessary control technology to meet the PTR mandates. Specifically, of the 185 control technology retrofit projects that EPA anticipates, only 27% can be completed by the EPA-proposed compliance dates. (This 27% represents the fraction of the total retrofit projects for which unit owners announced a completion date by January 1, 2012, or January 1, 2014, respectively, and which this analysis assumes will meet their owner-announced completion dates.) A total of 54 retrofit projects are predicted to miss the January 1, 2012, deadline; and 81 such projects are predicted to miss the January 1, 2014, deadline. Project completion dates persist well into 2016.

A fundamental flaw in EPA's evaluation is assuming the ability to deploy SCR and FGD in 21 and 27 months, respectively. Even if this unrealistic schedule could otherwise be met, it could not in fact be met due to a limit in boilermaker hours, using the 2008-2010 experience as a benchmark. The concentrated, simultaneous demands on equipment and services, particularly as manifested by the consumption of boilermaker hours, make compliance with EPA's proposed schedule impossible.

Moreover, this analysis does not take into consideration the additional impacts of other rulemakings on the availability of labor and tradespeople as well as engineering contractors. Examples include the recent cement kiln MACT standards, which will require a large number of kilns to install wet FGD systems over the next three years, and the ICI boiler and process heat MACT standards, which are expected to require hundreds of wet FGD systems and other types of controls to be installed by 2014 if EPA makes those standards final by next year. In addition, these rulemakings and the PTR itself will require, as part of any wet-FGD system installation, the construction of a new stack as a result of the increase in water vapor in the flue gas and its effect on stack flow properties as well as the construction or expansion of landfill capacity for byproducts of FGD system operation. Limits on the availability of qualified tradespeople and engineering and construction contractors for stack construction will also have a significant adverse impact on the ability to meet the PTR's compliance schedule. Consideration of these factors reinforces the conclusion that it will not be possible for regulated electric generating companies to meet the PTR's compliance schedule.

Attachment III

Tables Regarding Current Air Quality at Sites Projected to be Nonattainment Sites in 2012

Current Air Quality at Sites Projected to be Nonattainment Sites in 2012

Table I: Annual $PM_{2.5}$ NAAQS (1997)
Based on Table IV.C-7, 75 Fed. Reg. 45210, 45247 (Aug. 2, 2010).

Monitor ID	State	County	Current Air Quality Information
10730023	Alabama	Jefferson	
10732003	Alabama	Jefferson	
130210007	Georgia	Bibb	
130630091	Georgia	Clayton	
131210039	Georgia	Fulton	
170310052	Illinois	Cook	Final Rule -- determination of attainment -- 74 Fed. Reg. 62243 (Nov. 27, 2009)
171191007	Illinois	Madison	
171630010	Illinois	Saint Clair	
180190006	Indiana	Clark	Proposed Rule -- determination of attainment -- 75 Fed. Reg. 55727 (Sept. 14, 2010)
180372001	Indiana	Dubois	Final Rule -- determination of attainment -- 74 Fed. Reg. 62243 (Nov. 27, 2009)
180970078	Indiana	Marion	
180970081	Indiana	Marion	
180970083	Indiana	Marion	
211110043	Kentucky	Jefferson	Proposed Rule -- determination of attainment -- 75 Fed. Reg. 55727 (Sept. 14, 2010)
261630015	Michigan	Wayne	
261630033	Michigan	Wayne	
390170016	Ohio	Butler	
390350038	Ohio	Cuyahoga	
390350045	Ohio	Cuyahoga	
390350060	Ohio	Cuyahoga	
390610014	Ohio	Hamilton	
390610042	Ohio	Hamilton	
390610043	Ohio	Hamilton	
390617001	Ohio	Hamilton	
390618001	Ohio	Hamilton	
420030064	Pennsylvania	Allegheny	
420031301	Pennsylvania	Allegheny	
420070014	Pennsylvania	Beaver	
420710007	Pennsylvania	Lancaster	Final Rule -- determination of attainment -- 74 Fed. Reg. 48863 (Sept. 25, 2009)

Monitor ID	State	County	Current Air Quality Information
421330008	Pennsylvania	York	Final Rule -- determination of attainment -- 74 Fed. Reg. 48863 (Sept. 25, 2009)
540110006	West Virginia	Cabell	
540391005	West Virginia	Kanawha	

Table II: 24-hour $PM_{2.5}$ NAAQS (2006)

Based on Table IV.C-9, 75 Fed. Reg. at 45249.

Monitor ID	State	County	Current Air Quality Information
10730023	Alabama	Jefferson	Final Rule -- determination of attainment -- 75 Fed. Reg. 57186 (Sept. 20, 2010)
10732003	Alabama	Jefferson	Final Rule -- determination of attainment -- 75 Fed. Reg. 57186 (Sept. 20, 2010)
90091123	Connecticut	New Haven	
170310052	Illinois	Cook	Not currently designated nonattainment
170310057	Illinois	Cook	Not currently designated nonattainment
170310076	Illinois	Cook	Not currently designated nonattainment
170311016	Illinois	Cook	Not currently designated nonattainment
170312001	Illinois	Cook	Not currently designated nonattainment
170313103	Illinois	Cook	Not currently designated nonattainment
170313301	Illinois	Cook	Not currently designated nonattainment
170316005	Illinois	Cook	Not currently designated nonattainment
171190023	Illinois	Madison	Not currently designated nonattainment
171191007	Illinois	Madison	Not currently designated nonattainment
171192009	Illinois	Madison	Not currently designated nonattainment
171193007	Illinois	Madison	Not currently designated nonattainment
180190006	Indiana	Clark	Not currently designated nonattainment
180372001	Indiana	Dubois	Not currently designated nonattainment
180830004	Indiana	Knox	Not currently designated nonattainment
180890022	Indiana	Lake	Not currently designated nonattainment
180890026	Indiana	Lake	Not currently designated nonattainment
180970042	Indiana	Marion	Not currently designated nonattainment
180970043	Indiana	Marion	Not currently designated nonattainment
180970066	Indiana	Marion	Not currently designated nonattainment
180970078	Indiana	Marion	Not currently designated nonattainment
180970079	Indiana	Marion	Not currently designated nonattainment
180970081	Indiana	Marion	Not currently designated nonattainment
180970083	Indiana	Marion	Not currently designated nonattainment
181570008	Indiana	Tippecanoe	Not currently designated nonattainment
191630019	Iowa	Scott	Not currently designated nonattainment
210590005	Kentucky	Daviess	Not currently designated nonattainment

Monitor ID	State	County	Current Air Quality Information
211110043	Kentucky	Jefferson	Not currently designated nonattainment
211110044	Kentucky	Jefferson	Not currently designated nonattainment
211110048	Kentucky	Jefferson	Not currently designated nonattainment
245100040	Maryland	Baltimore City	Not currently designated nonattainment
245100049	Maryland	Baltimore City	Not currently designated nonattainment
261150005	Michigan	Monroe	
261250001	Michigan	Oakland	
261470005	Michigan	St. Clair	
261610008	Michigan	Washtenaw	
261630015	Michigan	Wayne	
261630016	Michigan	Wayne	
261630019	Michigan	Wayne	
261630033	Michigan	Wayne	
261630036	Michigan	Wayne	
290990012	Missouri	Jefferson	Not currently designated nonattainment
291831002	Missouri	Saint Charles	Not currently designated nonattainment
295100007	Missouri	St. Louis City	Not currently designated nonattainment
295100087	Missouri	St. Louis City	Not currently designated nonattainment
340171003	New Jersey	Hudson	
340172002	New Jersey	Hudson	
340390004	New Jersey	Union	
360050080	New York	Bronx	
360610056	New York	New York	
360610128	New York	New York	
390170003	Ohio	Butler	Not currently designated nonattainment
390170016	Ohio	Butler	Not currently designated nonattainment
390170017	Ohio	Butler	Not currently designated nonattainment
390171004	Ohio	Butler	Not currently designated nonattainment
390350038	Ohio	Cuyahoga	
390350045	Ohio	Cuyahoga	
390350060	Ohio	Cuyahoga	
390350065	Ohio	Cuyahoga	
390490024	Ohio	Franklin	Not currently designated nonattainment
390490025	Ohio	Franklin	Not currently designated nonattainment
390610006	Ohio	Hamilton	Not currently designated nonattainment
390610014	Ohio	Hamilton	Not currently designated nonattainment
390610040	Ohio	Hamilton	Not currently designated nonattainment
390610042	Ohio	Hamilton	Not currently designated nonattainment
390610043	Ohio	Hamilton	Not currently designated nonattainment
390617001	Ohio	Hamilton	Not currently designated nonattainment
390618001	Ohio	Hamilton	Not currently designated nonattainment
390811001	Ohio	Jefferson	

Monitor ID	State	County	Current Air Quality Information
391130032	Ohio	Montgomery	Not currently designated nonattainment
391530017	Ohio	Summit	
420030008	Pennsylvania	Allegheny	
420030064	Pennsylvania	Allegheny	
420030093	Pennsylvania	Allegheny	
420030116	Pennsylvania	Allegheny	
420031008	Pennsylvania	Allegheny	
420031301	Pennsylvania	Allegheny	
420070014	Pennsylvania	Beaver	
420110011	Pennsylvania	Berks	Not currently designated nonattainment
420210011	Pennsylvania	Cambria	
420430401	Pennsylvania	Daupin	
420710007	Pennsylvania	Lancaster	
421330008	Pennsylvania	York	
471251009	Tennessee	Montgomery	Not currently designated nonattainment
540090011	West Virginia	Brooke	
550790010	Wisconsin	Milwaukee	
550790026	Wisconsin	Milwaukee	
550790043	Wisconsin	Milwaukee	
550790099	Wisconsin	Milwaukee	

Table III: 8-hour Ozone NAAQS (1997)
Based on Table IV.C-11, 75 Fed. Reg. at 45252.

Monitor ID	State	County	Current Air Quality Information
220330003	Louisiana	East Baton Rouge	Final Rule -- determination of attainment -- 75 Fed. Reg. 54778 (Sept. 9, 2010)
361030002	New York	Suffolk	
361030009	New York	Suffolk	
421010024	Pennsylvania	Philadelphia	
480391004	Texas	Brazoria	
482010051	Texas	Harris	
482010055	Texas	Harris	
482010062	Texas	Harris	
482010066	Texas	Harris	
482011039	Texas	Harris	
484391002	Texas	Tarrant	