AN ASSOCIATION OF INDEPENDENT POWER PRODUCERS IN THE ANTHRACITE AND BITUMINOUS COAL REGIONS OF THE UNITED STATES

October 7, 2011

VIA HAND DELIVERY
Lisa P. Jackson
Administrator
Environmental Protection Agency
Ariel Rios South – Room 3000
1200 Pennsylvania Ave., NW
Mail Code 1101A
Washington, DC 20460

Re: Federal Implementation Plans: Interstate Transport of fine Particulate Matter and Ozone and Correction of SIP Approvals (Docket ID No. EPA-HQ-2009-0491); Petition for Reconsideration

Dear Ms. Jackson,

Enclosed please find ARIPPA's Petition for Reconsideration of EPA's final rule, "Federal Implementation Plans: Interstate Transport of fine Particulate Matter and Ozone and Correction of SIP Approvals", published at 76 Fed. Reg. 48,208 (Aug. 8, 2011).

Should you have any questions, please contact me at (717) 763-7635 or jamcnelly1@arippa.org.

Sincerely,

Jeff A. McNelly
ARIPPA Executive Director

cc: Ms. Meg Victor, EPA (via electronic mail)
Ms. Sonja Rodman, EPA (via electronic mail)

ARIPPA's Petition for Reconsideration of EPA's Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals

I. Introduction

In accordance with Section 307(d)(7)(B) of the Clean Air Act ("CAA"), 42 U.S.C. § 7607(d)(7)(B), ARIPPA hereby submits this Petition for Reconsideration of EPA's Final Rule, "Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals", published at 76 Fed. Reg. 48,208 (Aug. 8, 2011) (to be codified at 40 C.F.R. pts. 51, 52, 72, 78, and 97) ("CSAPR"). This Petition is submitted on behalf of ARIPPA's environmentally-beneficial, alternative energy electric generating member plants.

ARIPPA previously submitted comments on the proposed Transport Rule, published at 75 Fed. Reg. 45,210 (proposed Aug. 2, 2010) (the "Proposed Rule"), in October 2010. In October 2010, ARIPPA submitted comments on EPA's Notice of Data Availability for Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone; Proposed Rule, 75 Fed. Reg. 53613 (Sept. 1, 2010) (the "First NODA"). ARIPPA also submitted comments, in February 2011, on EPA's "Notice of Data Availability for Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone: Request for Comment on Alternative Allocations, Calculation of Assurance Provision Allowance Surrender Requirements, New-Unit Allocations in Indian Country, and Allocations by States", 76 Fed. Reg. 1,109 (Jan. 7, 2011) (the "Second NODA"). Finally, ARIPPA is simultaneously filing with this Petition for Reconsideration a Petition for Review of CSAPR with the United States Court of

Appeals for the D.C. Circuit, pursuant to CAA Section 307(b), in order to preserve ARIPPA's rights to seek judicial review of CSAPR.

II. <u>Historical Significance and Background</u>

ARIPPA plants are designed and operated to convert large quantities of coal refuse into alternative electricity, serving the energy needs of hundreds of thousands of households and businesses. Among the many benefits realized by the operation of the ARIPPA plants' circulating fluidized bed ("CFB") technology, coal refuse is converted into energy and the by-product ash residue is utilized to reclaim vacant and damaged abandoned mine lands and streams.

The coal refuse-to-alternative energy industry is truly unique, constituting one of the few fully-viable, environmentally-beneficial alternative energy industries. The Pennsylvania Department of Environmental Protection ("PADEP") recently promoted our industry's environmental benefits in its comments addressing EPA's proposed "Non-Hazardous Secondary Materials Identification" rule. PADEP stated that "[t]he most effective means of reclaiming these coal refuse piles is through the use of coal refuse as a fuel. Everything should be done to encourage this practice. Putting additional burdens on the re-mining of these piles, which will mean the continued pollution of Pennsylvania's rivers and streams, we believe EPA would agree is not a desirable outcome." The Office of Surface Mining Reclamation and Enforcement has similarly acknowledged the environmental benefits provided by coal refuse-fired plants in Pennsylvania with respect to reclaiming abandoned mine lands, honoring several mine reclamation projects associated with these facilities with national awards in recent years. Understanding the unique environmental advantages of the continued beneficial use of coal refuse is pivotal to understanding the importance of ARIPPA's concerns with CSAPR, and the environmental benefits preserved through the continued viability of our facilities.

III. Description of ARIPPA Member Facilities

Organized in 1988, ARIPPA is a non-profit trade association based in Camp Hill, Pennsylvania. Its membership is comprised of electric generating plants, producing alternative electrical energy and/or steam. Most ARIPPA member plants are currently located in or near the anthracite or bituminous coal regions of the United States. ARIPPA plants generate approximately 10% of the total electricity produced in the Pennsylvania-West Virginia region. Hundreds to thousands of citizen-workers, who are directly or indirectly employed by coal refuse-fired plants, live, along with their children, families, and extended families, in communities within close proximity of these alternative energy plants. The surrounding communities, lands, and streams have experienced vast environmental and economic improvements mainly due to the decades of hard work and dedication provided by these workers and the ARIPPA companies.

Member plants generate electricity using environmentally-friendly CFB boiler technology to convert coal refuse and/or other alternative fuels such as biomass into alternative energy and steam. Indeed, the fundamental purpose of the ARIPPA plants is to combust coal refuse material in order to reclaim abandoned lands, while generating alternative energy. The ARIPPA member facilities generate electricity for sale at a minimum capacity of more than 25 MWe. Today, there are CFB alternative energy plants converting coal refuse into electricity and steam in various states.

The ARIPPA coal refuse to alternative energy plants were originally constructed as Qualifying Facilities ("QFs"), subject to size restrictions pursuant to the Public Utility Regulatory Policy Act ("PURPA"). As a result, these facilities are relatively small in size, ranging from 30 megawatts ("MW") and averaging between 80 and 85 MW each. Moreover, expansion of such plants is severely constrained by federal, state and local regulatory requirements, including but not limited to, those imposed through permitting programs. More than half of the member plants operate under a long term "Power Purchase Agreement" ("PPA"), supplying alternative energy to utility companies at a fixed price. Accordingly, ARIPPA member facilities have continued to meet or exceed the increasingly stringent environmental compliance standards by directly absorbing increased compliance costs, without the ability to increase the rates assessed to electric utility rate payers.

In assessing the implication of its rulemaking actions, it is imperative that EPA take into account the environmental benefits associated with mine reclamation. In particular, many eastern states are faced with the environmental problems associated with abandoned mine lands, including but not limited to, surface and groundwater pollution, open entrances to abandoned mines, inadequately reclaimed coal refuse piles (some with dangerous highwalls), sediment-clogged streams, damage from landslides, and fumes and surface instability resulting from mine fires and open burning of coal refuse. Such environmental impacts have severely affected the surrounding communities, including with respect to economic growth. Facilities combusting coal refuse offer a mechanism for remedying these environmental concerns, while simultaneously generating electricity for consumptive use.

ARIPPA plants work closely with various local watershed groups as well as Earth Conservancy to reclaim abandoned mine lands and convert polluted streams into clean and usable waterways. This industry provides an option for removing coal refuse piles from the environment without shifting such costs to public sources. PADEP has testified that, should the coal refuse combustion option become unavailable, the resulting costs to remove the coal refuse piles in Pennsylvania could approach billions of dollars and require over 500 years to complete.

EPA recently recognized the environmental benefits provided by these plants in the context of its proposed rule addressing National Emission Standards for Hazardous Air Pollutants from electric generating units ("Utility MACT"). Specifically, EPA stated that "[u]nits that burn coal refuse provide multimedia environmental benefits by combining the production of energy with the removal of coal refuse piles and by reclaiming land for productive use. Consequently, because of the unique environmental benefits that coal refuse-fired EGUs provide, these units warrant special consideration . . . ." 76 Fed. Reg. 25,066. With this background in mind, ARIPPA requests that the Agency consider the comments for reconsideration below, submitted on behalf of ARIPPA's environmentally-beneficial, alternative energy electric generating member plants.

IV. Executive Summary

ARIPPA requests that EPA reconsider and revise CSAPR consistent with ARIPPA's specific comments detailed below. Most significantly, CSAPR should not apply to ARIPPA's coal refuse-fired CFB boilers, because EPA has not justified a finding of significant contribution as to these units. In developing an approach for controlling emissions under CSAPR, EPA concluded that multiple source categories are responsible for significant generation of nitrogen oxide ("NOx") and sulfur dioxide ("SO_2") emissions, including both EGUs and non-EGUs. Nevertheless, EPA concluded that the objectives of CSAPR can most cost-effectively be achieved by regulating only EGUs, based on EPA's belief that there are little or no reductions available for non-EGUs at costs lower than the thresholds EPA has chosen (i.e., $500/ton for NOx and $2,300/ton for SO_2).

EPA does not distinguish among EGUs within CSAPR, including on the basis of emissions characteristics, fuel source, operational design, emissions control options, or any other criteria. Instead, CSAPR applies to any stationary fossil fuel-fired boiler or combustion turbine qualifying as an EGU under the final rule. This approach is inappropriate and results in unsupportable applicability determinations. Specifically, the ARIPPA facilities exhibit certain fundamentally distinct characteristics relative to traditional EGUs, that distinguish ARIPPA plants from other EGUs; such distinctions are at least comparable to the distinguishing characteristics of non-EGUs deemed significant by EPA for purposes of regulation under CSAPR. However, EPA did not separately evaluate the ARIPPA units (or coal refuse-fired CFBs generally) as distinct source types in the rulemaking development process for CSAPR.

The CFB units operated by the ARIPPA plants exhibit numerous unique characteristics that distinguish them from traditional EGUs. First, CFB technology is inherently cleaner-burning and, therefore, its emissions characteristics, including for NOx and SO_2, are distinguishable from traditional EGUs. Second, because emission controls are primarily achieved through careful management of the combustion zone, CFB operators must maintain strict control over combustion zone characteristics in order to simultaneously control multiple pollutants.

These distinct emission control characteristics are significant with respect to CSAPR in at least two respects. First, the emission control technologies considered by EPA for application to EGUs under CSAPR do not readily extend to CFB technology. Second, the CFB technology designed for use by the ARIPPA member facilities was specifically intended to combust coal refuse as the primary or exclusive fuel source for energy generation. The application of this technology for this purpose was in response to the significant challenges caused by the depositing of thousands of tons of coal refuse within the Commonwealth, which created acid mining drainage and water pollution. Further, the ARIPPA plants are generally subject to legal requirements to combust coal refuse, at least as a primary fuel component. Accordingly, fuel switching is not an available control option.

EPA's cost-effectiveness analysis under CSAPR fails to account for these significant distinctions in coal refuse-fired CFB units, and, therefore, EPA's determination that EGUs can be cost-effectively controlled consistent with the objectives of CSAPR does not, in fact, apply to the CFB technology used by the ARIPPA facilities, any more than it would apply to non-EGUs excluded from regulation under CSAPR. In fact, because of the unique characteristics of ARIPPA's coal refuse-fired CFB units, the only theoretical option among the SO_2 reduction scenarios contemplated by CSAPR through which the ARIPPA plants might limit SO_2 emissions consistent with the Phase II allocation rates is installation of an add-on control device.

EPA apparently assumes that dry sorbent injection ("DSI") is an available technology for reducing SO_2 and acid gas emissions for coal refuse-fired CFB boilers. However, ARIPPA is not aware of a single commercially demonstrated retrofit application of DSI for the reduction of SO_2 emissions from a coal refuse-fired CFB boiler anywhere in the United States. Moreover, even to the extent that such control technology could be considered technically feasible, ARIPPA's analysis demonstrates that such technology could not be considered economically feasible, based on EPA's threshold for identifying cost-effective SO_2 controls of $2,300 per ton removed. Specifically, ARIPPA's analysis of the cost-effectiveness of using DSI to reduce SO_2 emissions demonstrates that it would cost *at least* $3,300 per ton of SO_2 removed, but more likely in excess of $6,400 per ton removed, depending on the sorbent injection rate required to achieve the necessary emission reductions in Phase II. Moreover, ARIPPA calculated these cost effectiveness values notwithstanding that its cost analysis is limited to the direct costs of installation and operation of DSI. In fact, because the application of such technology would likely severely degrade the quality of ash generated by coal refuse-fired CFB units, ultimately preventing the ash from being used beneficially in the reclamation of abandoned mines, the total cost per ton removed for reducing SO_2 emissions, taking into account the additional ash disposal cost, would increase to more than $11,500 per ton removed.

ARIPPA also evaluated the potential application of spray drying absorption ("SDA") as an SO_2 emission control option, and concluded that retrofitting a typical 80 MW coal refuse plant to meet the Phase II reduction requirements would cost nearly $9,000 per ton removed. Therefore, it is clear that there are no controls that are both technically and economically available to the ARIPPA plants for reducing SO_2 emissions to the levels required under CSAPR in 2014.

Absent a showing that emissions can be cost-effectively controlled from coal refuse-fired CFB units, EPA has not justified a finding of significant contribution from the ARIPPA plants. Relative to emission impacts, the emissions from the ARIPPA plants are materially less than traditional coal-fired EGUs. Therefore, without distinction for the unique emission profiles of these facilities, EPA inappropriately and inaccurately concludes that the ARIPPA EGUs contribute to downwind nonattainment to the same extent as traditional EGUs. Rather, evaluation of emission characteristics more closely aligns the ARIPPA facilities with the many emission sources that EPA has determined to exclude from regulation under CSAPR. For these reasons, EPA's analysis in support of CSAPR does not support a finding that the ARIPPA facilities significantly contribute to nonattainment in downwind states, nor that emissions from ARIPPA facilities can be cost-effectively controlled.

Finally, emissions from the ARIPPA plants comprise a small portion of Pennsylvania's total emissions budget. As such, a determination that the ARIPPA facilities are among a relatively small percentage of facilities significantly contributing to downwind nonattainment is not consistent with an accurate analysis of the emission inventory in Pennsylvania. Conversely, exclusion of the ARIPPA facilities from the

CSAPR standards will not materially impede Pennsylvania's efforts to limit emissions potentially contributing to downwind nonattainment. Accordingly, EPA should reconsider its finding of significant contribution as to the ARIPPA facilities, and revise CSAPR to exclude these facilities from the final regulation altogether.

The reduction in the SO_2 emission budgets for Pennsylvania and other states in the final regulation constitutes a fundamental change for which EPA has not provided sufficient notice or opportunity for comment or adequate support. In particular, between the proposed and final CSAPR, Pennsylvania's Phase I SO_2 budget was reduced by approximately 30%, while the state's Phase II SO_2 budget was reduced by more than 20%. When EPA submitted the final version of CSAPR to the Office of Management and Budget ("OMB") for interagency review, the OMB observed the "significant" differences in the state emission budgets between the final rule and the version originally proposed (in some cases, the final state budgets are more than 70% lower than in the proposed rule). EPA should therefore reconsider CSAPR on this basis, and provide affected sources and states an adequate opportunity to review and comment upon the revised state emission budgets.

The timing of the effectiveness of CSAPR will make it impossible for certain sources to demonstrate compliance by the applicable deadline. The first phase of SO_2 and NOx emission reductions under CSAPR begins on January 1, 2012 – less than five months from the promulgation date in the *Federal Register*. Although EPA clearly recognizes that affected sources will not be able to complete installation of advanced post-combustion controls before 2012, EPA's has nonetheless determined to proceed at this time by imposing a January 1, 2012 effective date under CSAPR.

As an alternative to installing advanced back-end controls by January 2012, EPA believes facilities can achieve the Phase I emission reductions by operating existing controls, fuel switching, and/or increasing dispatch of lower-emitting generation. However, for many facilities, including the ARIPPA plants, it is not feasible, due to technical limitations and other restrictions, to engage in fuel switching or rely on lower-emitting units. In such cases, affected source owners and operators are left with the impossible choice of either curtailing operations or purchasing allowances from their over-allocated competitors. In this way, CSAPR effectively requires certain facilities to pay other facilities for the continued right to operate. EPA has never implemented a regulatory scheme under which an affected facility is required to compensate another private party in order for the affected facility to preserve its operational viability, and, clearly, the CAA does not authorize EPA to mandate such wealth transfers among regulated sources.

In order to avoid this result, ARIPPA requests that the Agency revise the final rule to afford affected facilities a reasonable opportunity to implement the measures necessary to reduce emissions, by delaying the effective date of the initial phase of CSAPR beyond January 1, 2012. Such delay would enable many affected facilities the opportunity to choose between installing the requisite pollution controls before the revised, later effective date, and opting not to install such controls and planning instead to demonstrate compliance by purchasing allowances on the market. Specifically, ARIPPA requests that EPA postpone the applicability date for Phase I until January 1, 2014.

Likewise, ARIPPA also requests that EPA postpone the applicability date for Phase II, recognizing that it may not be possible for affected sources to design, construct, install, and commence operation of significant emission control systems by January 1, 2014. In order to ensure consistency between EPA's proposed timing for the implementation of the Utility MACT and CSAPR, ARIPPA requests that EPA delay the effective date for Phase II until January 1, 2016. Applying this alternative approach to Phase I, the initial requirements of CSAPR should apply two years prior to Phase II, and therefore commence on January 1, 2014.

Finally, EPA's promulgation of a Federal Implementation Plan ("FIP") under CSAPR prior to allowing states the opportunity to develop their own programs to address interstate pollution transport is contrary to CAA Section 110. EPA apparently acknowledges that individual states may face unique circumstances in implementing CSAPR that are most appropriately addressed at the state-level in determining the most effective implementation of the overall regulatory objectives. Yet, EPA has determined to directly promulgate a FIP as the initial step in implementing the CSAPR regulatory program. Accordingly, in order to ensure consistency between CSAPR and the CAA, EPA should delay the effective date of Phase I of the final rule to allow states sufficient time to develop SIPs to address the emission reduction goals identified in the final regulation through their own state-specific programs.

V. Comments for Reconsideration

A. CSAPR should not apply to ARIPPA's coal refuse-fired CFB boilers, because EPA has not justified a finding of significant contribution as to these units.

In developing an approach for controlling emissions under CSAPR, EPA considered emission estimates for a variety of sources, including "EGUs, nonEGU point sources, stationary nonpoint sources, onroad mobile sources, and nonroad mobile sources." *See* 75 Fed. Reg. 45,238. This analysis confirmed that multiple source categories are responsible for significant generation of NOx and SO_2 emissions, relative to the total emission inventories of the affected states. Although EPA's analysis did not assess the impacts of individual emission units (including on the basis of size and/or current levels of emissions controls), EPA nonetheless concluded that the objectives of CSAPR can most cost-effectively be achieved by regulating only a single category of sources – EGUs.

In the preamble to CSAPR, EPA explains that "[a]lthough the cost curves presented in [the final] rule only include EGU reductions, EPA also assessed the cost of SO_2 and NOx emission reductions available for source categories other than EGUs in the proposed rulemaking. This preliminary assessment in the rule proposal suggested that there likely would not be very large emission reductions available from EGUs before costs reach the point for which non-EGU sources have available reductions . . . . EPA revisited these non-EGU reduction cost levels in this final rulemaking and verified that there are little or no reductions available from non-EGUs at costs lower than the thresholds that EPA has chosen ($500/ton for NOx, $2,300/ton for SO_2)." 76 Fed. Reg. 48,249. For the reasons discussed below, EPA's categorization of the ARIPPA facilities under CSAPR is inconsistent with EPA's objectives for the rule, and results in distinctions in applicability of the regulation that are not supported by EPA's analysis.

(i) The CFB units used by the ARIPPA plants exhibit unique characteristics that distinguish them from traditional EGUs.

EPA does not distinguish among EGUs within CSAPR, including on the basis of emissions characteristics, fuel source, operational design, emissions control options, or any other criteria. Instead, CSAPR applies to *any* stationary fossil fuel-fired boiler or combustion turbine qualifying as an affected EGU under the final rule.[1] In this way, CSAPR at once eliminates from regulation numerous significant NOx and SO_2 emission sources based on categorical distinctions, while at the same time establishing a "one-size-fits-all" approach to regulating EGUs under CSAPR. EPA's approach of regulating all EGUs under CSAPR, without considering significant distinguishing characteristics among those EGUs, is inappropriate and results in unsupportable applicability determinations. Indeed, as discussed below, the ARIPPA facilities exhibit certain fundamentally distinct characteristics relative to traditional EGUs, that distinguish the ARIPPA plants from other EGUs; such distinctions are at least comparable to the distinguishing characteristics of non-EGUs deemed significant by EPA for purposes of regulation under CSAPR. However, in the rulemaking development process for CSAPR, EPA did not separately evaluate the ARIPPA units (or coal refuse-fired CFBs generally) as distinct source types. Had EPA performed such analyses, it would have concluded that the ARIPPA facilities should not be subject to CSAPR.

[1] According to CSAPR, the following units would qualify as EGUs subject to regulation: "[a]ny stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale." *See, e.g.,* 76 Fed. Reg. 48,385.

Unlike traditional EGUs, the ARIPPA facilities use CFB boiler technology to convert coal refuse and/or other alternative fuels, such as biomass, into electricity and steam. CFB technology is inherently cleaner-burning and, therefore, more environmentally friendly than traditional coal combustion technology. Therefore, the emission characteristics, including for NOx and SO_2, of the coal refuse-fired CFB units are distinguishable from traditional EGUs.

In addition, emission control is primarily achieved in the combustion zone of the ARIPPA CFB units, not through back-end control equipment. Specifically, the introduction of limestone into the circulating fluidized bed allows for the absorption of SO_2 and significant reductions in SO_2 emissions. Indeed, these plants were designed and built to achieve specific levels of SO_2 control (generally exceeding 90% SO_2 reduction) through limestone addition, in order to meet the Best Available Control Technology ("BACT") emission limits established when the plants were permitted. With respect to NOx, strict management of combustion zone characteristics limit the formation of NOx. Additionally, many ARIPPA plants employ selective non-catalytic reduction ("SNCR") to achieve enhanced NOx reductions. In both cases, the CFB technology emits substantially lower SO_2 and NOx emissions – per ton of fuel, per MMBtu/hr of heat input and per MW/hr energy output – than conventional coal-fired EGUs.

Moreover, because emission controls are achieved through careful management of the combustion zone, CFB operators must maintain strict control over combustion zone characteristics in order to prevent a shift in concentration of other pollutants. For example, to the extent a CFB operator increases limestone addition rates to attempt to achieve further SO_2 emission reductions, such adjustments can affect characteristics in the combustion zone in a way that influences NOx formation, as well as particulate and carbon monoxide emission rates. Further, these control techniques face asymptotic limitations in effectiveness. At a critical point, the facility must add significantly greater quantities of limestone to achieve modest incremental reductions in SO_2 emissions; for the reasons discussed above, such increases would also likely increase NOx and particulate emissions. Moreover, for certain CFB plants, it is not even possible to add sufficient quantities of limestone to achieve SO_2 emission rates comparable to the allowance allocation levels reflected by CSAPR, due to design characteristics, heat transfer limits, and permit restrictions.

Similarly, attempts to maximize NOx emission reductions without regard to other combustion chemistry will result in increases in carbon monoxide ("CO") emissions, and perhaps other constituents. Further, the ability of many of the ARIPPA plants to reduce NOx emissions is directly limited by permitting requirements restricting ammonia slip.

These distinct emission control characteristics are significant with respect to CSAPR in at least two respects. First, the emission control technologies considered by EPA for application to EGUs under CSAPR do not readily extend to CFB technology, in the same manner and extent as applied to traditional coal-fired units. While back-end emission control technology can be applied to CFB units under certain situations, unique boiler design and operational criteria create additional challenges to effective operation of these emission control systems. More significantly, the cost-effectiveness of such back-end controls is dramatically affected by these technology distinctions. Because the CFB technologies are inherently cleaner burning, the quantity of emissions available for back-end control is substantially reduced. In this way, the denominator of the cost-effectiveness calculation is substantially lower, on a relative scale. By contrast, the capital and operational costs associated with the back-end controls are not materially less for these smaller facilities, because of the inherent fixed cost capital requirements of these systems, and some unique issues posed by the distinct CFB technology.

Second, the CFB technology designed for use by the ARIPPA member facilities was specifically intended to combust coal refuse as the primary or exclusive fuel source for energy generation. As stated above, the application of the technology for this alternative energy generation constituted a response to the immense challenges posed by thousands of tons of coal refuse, creating acid mining drainage and polluting miles of streams and rivers. The CFB technology was designed to effectively combust coal refuse from past mining activities, thereby clearing thousands of acres of land, reclaiming previously abandoned mine lands and steams, and eliminating a major source of acid mine drainage.

Not only are these CFB units specifically designed to combust coal refuse rather than other fuel sources, the ARIPPA member facilities are generally subject to *legal* requirements to combust coal refuse, at least as a primary fuel component. These legal requirements derive not only from contractual commitments, but also standards imposed by the Federal Energy Regulatory Commission ("FERC") as part of the designation of these facilities as QFs; the QF designation is a condition of the facilities' financing contracts for the CFB units.

In evaluating emission control options under CSAPR, EPA considered opportunities available to regulated sources to engage in fuel switching, and such opportunities supported EPA's conclusion that EGUs may cost-effectively reduce SO_2 emissions. *See* 76 Fed. Reg. 48,283-84. EPA's analysis of the cost-effectiveness of fuel switching as an emission control option did not extend beyond bituminous and subbituminous coal; this analysis does not consider non-traditional coal used as fuel, notably including coal refuse, which is distinguishable from other coal species in terms of sulfur content and other key characteristics. For the technological, legal, economic and practical reasons identified above, the ARIPPA facilities *cannot* simply elect to convert their fuel source from coal refuse to a lower-sulfur fuel in order to reduce emissions, and therefore allowance requirements, as contemplated by EPA under CSAPR.[2] Indeed, the fundamental purpose of the ARIPPA plants is to combust coal refuse to reclaim former mining lands while allowing for the production of electricity; switching fuels would therefore be directly inconsistent with this purpose.

Additionally, even to the extent that it would possible for the AIRPPA plants to switch to a lower-sulfur fuel, such change would have negative impacts from an environmental standpoint. If the ARIPPA plants were to discontinue combusting coal refuse (or even reduce the coal refuse combustion rate), then the many remaining piles of coal refuse in Pennsylvania would continue to contribute to greater acid mining drainage and associated water pollution over time.

EPA's cost-effectiveness analysis under CSAPR fails to account for these significant distinctions in coal refuse-fired CFB units. In this regard, EPA's

[2] Although the ARIPPA facilities cannot substitute lower sulfur fuels for coal refuse in the operation of the CFB units, it should be noted that many of these facilities are nonetheless subject to permit-based fuel-sulfur limitations or required percent reductions in sulfur content.

determination that EGUs – as a single category of sources – can be cost-effectively controlled consistent with the objectives of CSAPR does not, in fact, apply to the CFB technology utilized by ARIPPA facilities, any more than it would apply to non-EGU stationary sources excluded by EPA from regulation under CSAPR.

To illustrate this point, ARIPPA conducted an evaluation of the relative cost-effectiveness of the compliance options available to the ARIPPA plants for reducing SO_2 emissions to the levels reflected in the allowance allocations provided during Phase II of CSAPR. The results of this evaluation are detailed in Attachment A to this Petition. The analysis reflects consideration of the control options theoretically available to the ARIPPA facilities to reduce SO_2 emissions: reduce fuel sulfur, increase the use of limestone, or employ an add-on SO_2 emission control device, such as DSI or SDA. As described above, however, because of the unique characteristics of ARIPPA's coal refuse-fired CFB units, the ARIPPA plants cannot feasibly achieve material SO_2 reductions by either reducing fuel sulfur or increasing limestone utilization. Accordingly, the only theoretical option among these three SO_2 reduction scenarios through which the ARIPPA plants might limit SO_2 emissions to levels commensurate with the Phase II allocation rates is installation of an add-on control device.

In EPA's recently-issued proposed Utility MACT, the Agency apparently assumes that DSI is an available technology for reducing SO_2 and acid gas emissions from coal refuse-fired CFB boilers. In fact, however, ARIPPA is not aware of a single commercially demonstrated application of add-on, back-end DSI for the control of SO_2 emissions from a coal refuse-fired CFB unit anywhere in the United States. Under established CAA precedent, therefore, DSI cannot be considered a "technically feasible" control option for the reduction of SO_2 emissions from this source type.

Moreover, even to the extent that such emission control technology could be considered technically feasible, ARIPPA's analysis demonstrates that such technology could not be considered economically feasible. For purposes of developing the final emission reduction requirements under CSAPR, EPA determined that it is cost-effective for *all* EGUs in Group 1 states to control SO_2 emissions beginning in 2014 at rates up to $2,300/ton. *See* 76 Fed. Reg., 48,249. *See also* 76 Fed. Reg. 48,252 ("The cost curves demonstrate that sources begin to build significant . . . additional dry sorbent injection (DSI) retrofits at an SO_2 cost threshold of $2,300 per ton."). By contrast, ARIPPA's analysis of the cost-effectiveness of utilizing DSI to reduce SO_2 emissions demonstrates that it would cost *at least* $3,300 per ton removed for a typical 80 MW ARIPPA plant to reduce SO_2 emissions to the extent needed to satisfy the applicable 2014 emission reduction requirements (the underlying data supporting this conclusion are detailed in Attachment A).[3] However, this is a conservative, "best case" projection, based on the assumption that DSI will in fact provide the required emission reductions at a relatively low sorbent injection rate. More likely, based on recent applications of DSI (both permanent and test applications) which have demonstrated that significantly higher sorbent injection rates are required for effective SO_2 control, employing DSI to achieve the required SO_2 reductions would cost more than $6,400 per ton removed. Therefore, contrary to EPA's assumptions in the preamble to the final rule, it would *not* be cost-effective for ARIPPA's coal refuse-fired CFB units to install and operate DSI to

[3] This analysis is based on a typical ARIPPA coal refuse-fired CFB plant, which was the subject of a recent EPA-sponsored study of DSI costs.

reduce SO_2 emissions, applying EPA's own threshold for identifying cost-effective controls.

Moreover, ARIPPA's foregoing cost-effectiveness analysis is limited to the direct costs of installation and operation of the emission control device. In fact, application of such technology is likely to severely degrade the quality of ash generated by coal refuse-fired CFB units. Currently, such ash is beneficially used for the reclamation of abandoned mines. This management process not only provides environmental benefits in terms of mine reclamation, but substantially reduces the cost otherwise required for ash disposal. The addition of significantly greater amounts of sorbent is likely to impair the quality of the ash, in terms of pH, leachability of metals, increased chlorides, sulfates, and other characteristics. The resulting ash parameters would likely dictate the need for disposal in lined landfills, rather than mine reclamation, at a current cost of approximately \$28 to \$40 per ton. Taking into account this additional ash disposal cost, the cost per ton for reducing SO_2 emissions would increase to more than \$11,500 per ton removed – *five times* the \$2,300 cost threshold identified by EPA as cost-effective for this purpose. *See* Attachment A.

ARIPPA also evaluated the potential application of SDA as an SO_2 emission control option, notwithstanding that, as with DSI, ARIPPA is not aware of a single commercially demonstrated retrofit application of SDA for the control of SO_2 emissions from a coal refuse-fired CFB unit anywhere in the United States. For a typical 80 MW ARIPPA plant, the control cost for reducing SO_2 emissions to meet the Phase II reduction requirements using SDA would be nearly \$9,000 per ton removed. As shown in the Attachment to this Petition, this estimate includes the annual operating costs for an SDA system, which would be significant, including sorbent and water use, consumptive power demands, system operation and maintenance, and additional waste disposal costs. Clearly, this cost estimate substantially exceeds the control cost threshold selected by EPA as cost-effective for reducing SO_2 emissions from all EGUs under CSAPR.

Based on the results of ARIPPA's analysis, it is clear that there are no controls that are both technologically and economically available to the ARIPPA plants for reducing SO_2 emissions to the levels required under CSAPR in 2014. ARIPPA's evaluation also demonstrates that the effectiveness of using back-end controls to reduce SO_2 emissions from coal refuse-fired CFB units is currently uncertain at best, with most current applications still in experimental stages. Such uncertainty only exacerbates the challenges faced by these plants as a result of the virtually-immediate applicability of the final rule. This conclusion is consistent with EPA's recent determination (as articulated in the context of EPA's proposed New Source Performance Standards for fossil fuel-fired electric utility units) that it is not cost-effective to add additional post-combustion SO_2 controls to modified fluidized bed combustion sources. *See* 76 Fed. Reg. 25,066.

(ii) Absent a showing that emissions can be cost-effectively controlled from coal refuse-fired CFB units, EPA has not justified a finding of significant contribution from the ARIPPA plants.

Given the distinguishing characteristics of the ARIPPA facilities (based primarily on use of CFB technology and combustion of coal refuse), as detailed above, it is clear that EPA's analysis of "significant contribution" under CSAPR as applied to traditional EGU's is inapplicable to the ARIPPA plants. Specifically, EPA's evaluation depends, in material part, upon an evaluation of the emission characteristics and the cost-effectiveness of available controls for EGUs. In the context of emission impacts, the emissions from the ARIPPA facilities are materially less than traditional coal-fired EGUs. Therefore, to the extent that EPA evaluates the air quality impacts from EGUs as a single category, without distinction for the unique emission profiles of these facilities, EPA inappropriately and inaccurately concludes that the ARIPPA EGUs contribute to downwind nonattainment to the same extent as traditional EGUs. Instead, the emission characteristics of the ARIPPA CFB units distinguish these sources from traditional coal-fired EGUs. In fact, evaluation of emission characteristics more closely aligns the ARIPPA facilities with the many emission sources that EPA has determined to exclude from regulation under CSAPR.

Likewise, under the second part of EPA's "significant contribution" analysis, EPA's determination that EGUs may be cost-effectively controlled simply does not apply to the ARIPPA facilities. Most significantly, the emission reduction techniques identified by EPA are either inapplicable to the ARIPPA facilities or would necessitate a substantially different control analysis.

Instead, the ARIPPA facilities' are more closely related to non-EGUs, such as biomass units, which EPA has concluded do not significantly contribute to downwind nonattainment. EPA's basis for this distinction under CSAPR is that non-EGUs cannot achieve comparable cost-effective emissions reductions. Specifically, EPA states that "there are little or no reductions available from non-EGUs at costs lower than the thresholds that EPA has chosen ($500/ton for NOx, $2,300/ton for SO_2)." 76 Fed. Reg. 48,249. Similarly, in the preamble to the proposed Transport Rule, EPA explained that its "review of the costs of EGU and non-EGU controls resulted in a conclusion that substantial SO_2 and NOx reductions from EGUs are available at a cost per ton that is lower than the cost per ton of non-EGU controls." 75 Fed. Reg. 45,300. Therefore, because EPA proposes to distinguish source categories on the basis that specific design and/or operating characteristics make it economically infeasible for such source categories to comply with the emission reduction requirements in CSAPR, ARIPPA's CFB units should not be included among the sources subject to regulation under the final CSAPR rule.

For these reasons, EPA's analysis as reflected in CSAPR does not support a finding that the ARIPPA facilities significantly contribute to nonattainment in downwind states, nor that emissions from ARIPPA facilities can be cost-effectively controlled.

In addition, within the preamble to the proposed Transport Rule, EPA sets forth several objectives for the development of this regulation. These stated objectives further demonstrate the inapplicability of EPA's regulatory analysis to the ARIPPA plants. Specifically, EPA carefully enumerates "key guiding principles" for determining to regulate specific sources. 75 Fed. Reg. 45,226-27. Among these guiding principles, EPA states that its proposed regulatory approach would provide for "cost effectiveness," as well as providing incentives and flexibility to the regulated community. For the reasons discussed above, these guiding principles are not satisfied with respect to the ARIPPA facilities, predominately because the proposed emission reductions cannot be achieved cost-effectively, and the regulatory standards not only afford no flexibility to the ARIPPA plants, but instead would establish requirements that these facilities cannot readily satisfy. The fact that EPA's guiding principles for CSAPR would not be served through regulation of the ARIPPA facilities provides further evidence that such regulation is inconsistent with EPA's analysis reflected in the rulemaking development process, and that these sources should therefore be excluded from EPA's final approach toward interstate transport regulation.

Finally in this context, emissions from the ARIPPA plants comprise a small portion of Pennsylvania's total emissions budget. Indeed, the collective SO_2 emissions from the ARIPPA plants in Pennsylvania and West Virginia represent *only 0.5%* of the aggregate SO2 emissions from the Group 1 states. As such, a determination that the ARIPPA facilities are among a relatively small percentage of facilities significantly contributing to downwind nonattainment is not consistent with an accurate analysis of the emission inventory for Pennsylvania. Similarly, exclusion of the ARIPPA facilities from regulation under CSAPR would not have a meaningful impact on Pennsylvania's overall emissions budget or EPA's analysis of the projected downwind impact from the State.

For the foregoing reasons, EPA should reconsider its finding of significant contribution as to the ARIPPA facilities and revise CSAPR to exclude these facilities from the final regulation.

B. The reduction in the SO_2 emission budgets for Pennsylvania and other states from the proposed Transport Rule to the final regulation constitutes a fundamental change for which EPA has not provided sufficient opportunity for notice and comment or adequate support.

(i) The final SO_2 emission budgets for Pennsylvania and other states were never subject to proper notice and comment procedures.

In accordance with the Administrative Procedures Act ("APA"), EPA is required to publish notice of a proposed rule in the *Federal Register*, and then "give interested persons an opportunity to participate in the rulemaking through submission of written data, views, or arguments . . . ." 5 U.S.C. § 553. The *Federal Register* notice must include the "terms or substance of the proposed rule or a description of the subjects and issues involved". 5 U.S.C. § 553(b)(3). The D.C. Circuit Court of Appeals interpreted these provisions of the APA in *Int'l Union, United Mine Workers of Am. v. Mine Safety & Health Admin.*, finding that the "[n]otice requirements are designed (1) to ensure that agency regulations are tested via exposure to diverse public comment, (2) to ensure fairness to affected parties, and (3) to give affected parties an opportunity to develop evidence in the record to support their objections to the rule and thereby enhance the quality of judicial review." 407 F.3d 1250, 1259 (2002).

ARIPPA acknowledges that a final rule may differ from a proposed rule to the extent that the final rule is a logical outgrowth of the proposed rule, and that such latitude is necessary to enable administrative agencies to effectively develop and implement regulations without having to subject every minor revision to notice and comment procedures. However, EPA's authority in this regard is limited and should be exercised sparingly.

The Office of Management and Budget ("OMB") noted, when EPA submitted the final Transport Rule for interagency review, that the final rule is "significantly different . . . than originally proposed," based on the "sheer magnitude of change to the budgets of all of the states." OMB pointed out that EPA made "dramatic" reductions of up to 69% in states' 2012 SO_2 budgets, and up to 72% in states' 2014 SO_2 budgets. *Id.* at 12. For example, New Jersey's 2012 and 2014 SO_2 budgets (before accounting for variability) are approximately 50% lower than in the proposed rule; Ohio's 2012 and 2014 SO_2

budgets are, respectively, approximately 35% and 25% lower than in the proposed rule; and New York's 2012 and 2014 SO_2 budgets are, respectively, approximately 60% and 55% lower than in the proposed rule. *See* 75 Fed. Reg. 45,291; 76 Fed. Reg. 48,262.

As stated above, nearly all of the ARIPPA facilities are located in Pennsylvania. Under the proposed Transport Rule, the SO_2 emission budgets (before accounting for variability) for Pennsylvania in Phases I and II were 388,612 tons and 141,693 tons, respectively. 75 Fed. Reg. 45,291. By contrast, under the final CSAPR, the SO_2 emission budgets for Pennsylvania in Phases I and II are merely 278,651 tons and 112,021 tons, respectively. 76 Fed. Reg. 48,262. Therefore, between the proposed and final CSAPR, Pennsylvania's Phase I SO_2 budget was reduced by approximately 30%, while the state's Phase II SO_2 budget was reduced by more than 20%. These reductions illustrate OMB's observation that EPA dramatically reduced the state emission budgets, including Pennsylvania's SO_2 budgets, between publication of the proposed and final versions of CSAPR.

Under CSAPR, the states' emission budgets represent the maximum number of allowances that may be allocated among all of the affected units within a particular state. Based on this framework, a reduction in a state's SO_2 emission budgets necessarily means that the affected sources in that state will receive fewer SO_2 allowances for the relevant control period. The states' budgets also represent the level of emissions above which CSAPR's assurance provisions are triggered in a given state. Accordingly, a significant reduction in the emission budgets for any state, including Pennsylvania, would materially impact the affected source owners and operators in that state.

The substantial reduction in Pennsylvania's statewide budget takes on increased significance when considered in light of the virtually-immediate applicability of the CSAPR standards. Affected facilities are afforded very little time to prepare compliance plans for implementation on January 1, 2012. These compliance plans must now account for the material reduction in the total availability of allowances for the state. Further, the reduction in the state's budget not only imposes additional stringency on a facility-specific allocation basis, but also creates increased risk for a source relying on allowance trading as a compliance option. Because of the assurance provisions included in CSAPR, an affected source must rely on in-state allowances in order to confidently avoid the punitive effect of the rule's assurance provisions. The significant reduction in available allowances for Pennsylvania sources reflected in the final CSAPR regulation compromises the ability of any facility to secure and rely upon allowances from other sources as its intended means of compliance, particularly under Phase I of the rule. Moreover, under EPA's proposed rule, the assurance provisions were not scheduled to take effect until the beginning of Phase II, and, according to the proposal, would only have required a surrender of one additional allowance per ton of excess emissions above the state's assurance level. 76 Fed. Reg. 48,296. Therefore, based on the proposed rule, affected facility owners were not anticipating having to demonstrate compliance subject to the assurance provisions until Phase II (i.e., by which time such facilities would have had the opportunity to install necessary pollution controls), nor were they expecting the imposition of an allowance surrender penalty that is *twice* as stringent as that initially proposed.

The dramatic reduction in the SO_2 budgets for Pennsylvania, coupled with the material impacts that such reduced budgets will necessarily have on affected facilities in the Commonwealth, renders the reduction in the relevant budgets a fundamental change to the proposed rule that goes well beyond a logical outgrowth of EPA's initial proposal.[4] According to the APA, notice of such change should have been published in the *Federal Register*, and interested persons should have been given the opportunity to provide additional comments. However, because EPA made the relevant changes to the emission budgets *after* notice of the proposed rule was published in the *Federal Register*, and *after* interested parties had already submitted their comments on the proposed rule, EPA's incorporation of the revised budgets into the final CSAPR violated the applicable provisions of the APA governing proper notice and comment procedures.

In the instant case, affected source owners and operators relied upon the emission budgets in the proposed Transport Rule to preliminarily evaluate compliance obligations and control strategies. However, these facilities did not anticipate, nor were they given a reason to anticipate, that the relevant budgets would be revised in such a meaningful way between the proposed and final rules. For these reasons, such parties should have been afforded an opportunity to comment on the revised budgets before they were finalized. Because EPA did not provide affected source owners and operators with sufficient notice and comment opportunities prior to issuing the final Transport Rule, EPA effectively made a fundamental change to the underlying

[4] Numerous parties affected by CSAPR have already filed challenges with the D.C. Circuit Court of Appeals, arguing, among other things, that the dramatic reductions in the statewide emission budgets from the proposed Transport Rule to the final regulation constitutes a fundamental change for which EPA has not provided sufficient opportunity for notice and comment or adequate support. *See EME Homer City Generation , L.P. v. EPA*, Case No. 11-1302.

regulation in contravention of the applicable requirements for notice and comment under the APA. EPA should therefore reconsider CSAPR on this basis, and provide affected sources and states an adequate opportunity to review and comment upon the revised state emission budgets. Indeed, EPA has already publicly stated that it plans to revise the final allowance allocations under CSAPR in order to provide additional allowances to certain states and/or facilities.

(ii) EPA did not provide adequate justification supporting the significant reductions in the SO_2 emission budgets for Pennsylvania and other states.

EPA's explanation of the basis for the significantly reduced final emission budgets in the preamble to CSAPR, as well as the underlying supporting documentation made available by EPA, is inadequate to justify such a fundamental change between the proposed and final versions of the rule. CAA Section 307(d)(6)(A)(ii) requires that the promulgation of any rule addressing a NAAQS under CAA Section 109 "be accompanied by . . . an explanation of the reasons for any major changes in the promulgated rule from the proposed rule." 42 U.S.C. § 7607(d)(6)(A)(ii); *see also National Resources Defense Council v. Thomas*, 805 F.2d 410, 418 n. 13 (D.C. Cir. 1986) (finding EPA provided sufficient explanation for changes from proposed to final NOx standard because EPA analyzed and discussed data at length, and provided a reasoned explanation for the changes to the standards). Notwithstanding this statutory directive, however, in the preamble to CSAPR, EPA only identifies a limited number of reasons as justification for the changes in the base case emissions (and, therefore, the state emission budgets).

First, EPA explains that, in developing the proposed rule, the Agency used a complex approach based on a comparison of historic and projected unit-level emissions in each state to establish 2012 budgets for Group 2 SO_2, annual NOx, and ozone-season NOx. According to EPA, it used this approach because, at the time of proposal, the Agency believed that historic 2009 emissions data were in some cases more representative of expected emissions in 2012 than strict modeling projections made at the time. However, since the proposal, EPA has made "significant" updates to the model used to calculate the state budgets, including, most notably, the incorporation of 2009 historic data directly into the modeling parameters. EPA admits that the application of this revised budgeting methodology results in a tightening of budgets in states whose projected emissions decline from 2012 to 2014 as the cost threshold is held constant.

Second, EPA notes that, when it calculated the proposed emission budgets, the cost thresholds (from which the state emission budgets are ultimately derived) for each pollutant were examined independently with no emission control cost assumed for the other pollutant standards (e.g., the cost thresholds for SO_2 were examined independently with no emission control cost assumed for either annual or ozone-season NOx). By contrast, in developing the final CSAPR, EPA analyzed the cost thresholds for each pollutant (i.e., SO_2, annual NOx, and ozone-season NOx) simultaneously. EPA explains that it was able to conduct this type of analysis for the final rule because the preliminary cost evaluations specific to annual and ozone-season NOx suggested little flexibility in adjusting the $500/ton cost thresholds imposed for NOx. In turn, EPA determined to hold the cost threshold constant at $500/ton for annual and ozone-season NOx in its examination of SO_2 at various cost thresholds. EPA believes this approach to cost analysis is a better indicator of CSAPR's likely impact on covered sources, because, for example, covered sources in states regulated for PM2.5 must address compliance requirements for SO_2 and NOx emissions simultaneously.

EPA's explanation of these differences in methodology are not accompanied by sufficient detail concerning the model inputs, parameters and output to enable a thorough evaluation of these changes. More importantly, affected states and facilities were not afforded any opportunity to comment upon this alternative methodology prior to EPA's application. Finally in this context, EPA does not justify the relationship between this revised methodology and any analysis of "significant impact" in downwind states, beyond considerations of cost-effective controls. For these reasons, the preamble to the final CSAPR provides an insufficient justification for such a meaningful change between the proposed and final versions of CSAPR, particularly when coupled with the fact that interested parties were not afforded sufficient notice and comment opportunities prior to incorporation of the reduced budgets into the final rule.

For the reasons discussed above, EPA should reconsider CSAPR by affording affected states and sources an opportunity to thoroughly review and comment upon the bases for and changes in the state-specific budget determination, and the final rulemaking should address such comments..

C. The timing of the effectiveness of CSAPR will make it impossible for certain sources to demonstrate compliance by the applicable deadlines.

(i) The applicability date for Phase I is overly stringent and will force certain under-allocated sources to either shut down or pay their competitors for the continued ability to operate.

The first phase of SO_2 and NOx emission reductions under CSAPR begins on January 1, 2012 – *less than five months from the promulgation date in the Federal Register*. EPA clearly recognizes in the preamble to CSAPR that it is impossible for affected facilities to install the advanced post-combustion controls required for larger emission reductions, such as wet/dry flue gas desulfurization ("FGD") scrubbers, and selective catalytic reduction ("SCR") and DSI systems, before 2012. 76 Fed. Reg. 48,252 ("EPA acknowledges that [advanced post-combustion control] installations are not feasible by 2012); 76 Fed. Reg. 48,280 ("EPA recognizes that the 6-month time frame between rule finalization and start of the first compliance period would not allow for the installation of a major post-combustion . . . control . . . ."); 76 Fed. Reg. 48,282 ("EPA believes that the January 1, 2014 compliance date is as expeditious as practicable for the sources installing large, complex control systems."). Indeed, EPA even acknowledges that installing FGD and SCR retrofits by *2014* will be difficult, requiring "aggressive action", including "parallel permitting" and "overtime and/or two-shift work schedules". 76 Fed. Reg. 48,282-83.[5] Despite the Agency's clear recognition of these limitations, EPA has determined to proceed at this time by imposing a January 1, 2012 effective date under CSAPR.

As an alternative to installing advanced back-end controls by January 2012, EPA believes that facilities can achieve the Phase I emission reductions by operating existing controls, fuel switching, and/or increasing dispatch of lower-emitting generation. *See, e.g.,* 76 Fed. Reg. 48,252 (EPA states that Phase I "SO_2 and NOx reductions come

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[5] EPA also admits that its schedule assumptions – 27 months for wet FGD and 21 months for SCR – are only "reasonable expectations for sources that have completed most of their preliminary project planning and can quickly make commitments to proceed." 76 Fed. Reg. 48,282-83. However, "[t]hese schedules do not include the extensive time that some plant owners might spend in making a decision on whether or not to retrofit." *Id.*

from operating existing controls, installing combustion controls, fuel switching, and increased dispatch of lower-emitting generation which can be achieved by 2012. In general, compliance mechanisms that do not involve post-combustion control installation are feasible before 2014."). However, for many facilities, including the ARIPPA plants, it is not feasible, due to technical limitations and other restrictions, to engage in fuel switching or rely on lower-emitting units. Even to the extent that such options are technologically feasible for affected facilities, in many cases implementation of these options is insufficient to generate the level of emission reductions necessary to satisfy the Phase I requirements. In such cases, affected source owners and operators are left with the impossible choice of either curtailing operations or purchasing allowances from their over-allocated competitors.

Even to the extent that it would be technologically feasible for affected facilities to scale-back operations without completely shutting down, generating electricity at the substantially-reduced rates necessary to achieve the required emission reductions would diminish electric reliability, while driving-up electricity costs (ultimately impacting consumers) and eliminating jobs. *See* EPA, Office of Air and Radiation, Regulatory Impact Analysis for the Final Transport Rule, Docket ID No. EPA-HQ-OAR-2009-0491 (2011), at 14 ("the projected annual incremental private costs of the selected remedy option (air quality-assured trading) to the power industry are $1.4 billion in 2012" (in 2007 dollars), and "[r]etail electricity prices are projected to increase nationally by an average of 1.3% in 2012"). Indeed, independent financial analysts are projecting that CSAPR will result in increased operating costs for facilities that rely on coal-fired generation and, in turn, increased wholesale power prices. *See* Standard & Poor's, Global Credit Portal Ratings Direct, *Why Casper, The EPA's Cross-State Air Pollution Rule, Is Spooking the Electricity Sector* (Sept. 12, 2011), at 11-12 (noting that forward power prices in certain regions have already increased in response to CSAPR, as compared to forward prices in June). Analysts have also recognized that concerns about electricity reliability may arise in regions where coal plants are being retired to meet CSAPR. *Id.* at 13.[6]

Consequently, for affected facilities with emission rates exceeding allocation levels during Phase I, the *only* viable compliance demonstration option is to purchase allowances on the market from competitors with "surplus" allowances. *See Appalachian Power Co. v. EPA*, 249 F.3d 1032, 1054 (D.C. Cir. 2001) (reasoning that ability of facilities subject to the NOx SIP Call to purchase additional allowances to demonstrate compliance "is no answer" to explain EPA's flawed allowance allocation methodology). As such, CSAPR effectively requires certain facilities to pay other facilities for the continued authority to operate. EPA has not previously implemented a regulatory scheme under which an affected facility is required to compensate another private party in order for the affected facility to preserve its operational viability. Clearly, the CAA does not authorize EPA to mandate such wealth transfers among regulated sources.

In order to avoid this result, ARIPPA requests that the Agency revise the final rule to afford affected facilities a reasonable opportunity to implement the measures necessary to reduce emissions, by delaying the effective date of the initial phase of CSAPR beyond January 1, 2012. Such delay would enable many affected facilities the opportunity to choose between installing the requisite pollution controls before the

[6] Numerous parties challenging CSAPR before the D.C. Circuit Court of Appeals have argued, among other things, that the rule will have a negative impact on electricity reliability. *See EME Homer City Generation , L.P. v. EPA*, Case No. 11-1302.

revised, later effective date, and opting not to install such controls and planning instead to demonstrate compliance by purchasing allowances on the market (thereby accepting the associated risks), rather than being forced into a position where their only option for compliance is to purchase allowances.[7]

Consistent with this analysis, ARIPPA notes that EPA states in the preamble to CSAPR that its "projections of retrofit activity under the final Transport Rule are highly compatible with its projections of retrofit activity under the proposed [Utility MACT]." 76 Fed. Reg. 48,283. Yet, in the context of EPA's discussions addressing the Proposed Utility MACT, which EPA currently expects to finalize in November 2011, EPA recognizes that affected sources will likely require an additional year – beyond the three years mandated by CAA Section 112 – to take the necessary measures to demonstrate compliance with the final Utility MACT. 76 Fed. Reg. 25,054-55. Based on this anticipated schedule, affected utility units theoretically would not be required to achieve the emission reductions mandated by the Utility MACT until the fall of 2015 at the earliest – nearly *four years after* CSAPR takes effect in January 2012.

Finally, as with any agency rulemaking of this level of complexity, it is critical that EPA have sufficient time following the promulgation of the final regulation, but before the rule becomes effective, to evaluate questions related to the application of the rule, and to provide clarification where needed. CSAPR is a complicated air quality

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[7] It is particularly significant in this context that the immediate applicability of the CSAPR requirements and the reduction in state allowance budgets reflected in the final CSAPR regulation contribute to uncertainty regarding the availability of sufficient allowances for trade. In addition, CSAPR's assurance provisions dictate that, even to the extent that an affected facility can identify and secure surplus allowances from a facility located in another state, the acquiring facility cannot ensure compliance by its own actions because of the uncertainties of the aggregate emissions profile for all affected sources within the state. In such case, the regulated source may be facing highly punitive penalty provisions, which in turn require the source to find and secure yet more allowances, the availability of which is far from clear under the current scheme.

regulation, which understandably includes certain provisions requiring further clarification by the Agency. These inconsistencies and potentially unclear provisions could lead to multiple interpretations and inconsistent application of the rule to similarly situated sources. Given these circumstances, EPA needs sufficient time – i.e., longer than the four and half months between the rule's promulgation and effective date – to further evaluate the rule, offering clarifications where needed, before it becomes effective.

For the reasons discussed above, ARIPPA requests that EPA reconsider CSAPR by delaying the effective date for the first phase of emission reductions until January 1, 2014, as specifically explained below in Section III.C(ii).

(ii) CSAPR's January 1, 2014 applicability date for Phase II is improperly aggressive and does not afford affected facilities sufficient time to install necessary pollution controls.

In the preamble to CSAPR, EPA clearly acknowledges the challenges faced by regulated entities to design, construct, install, and commence operation of significant emission control systems by January 1, 2014. *See, e.g.,* 76 Fed. Reg. 48,282-83. Specifically, EPA recognizes that installing FGD and SCR retrofits by 2014 will be very difficult, requiring "aggressive action", including "parallel permitting" and "overtime and/or two-shift work schedules". *Id. See also* 76 Fed. Reg. 48,282 (noting that "any other unit that might choose to retrofit FGD for a January 2014 compliance date will likely have to use various methods to accelerate the project schedule"). EPA also admits that its schedule assumptions – 27 months for wet FGD and 21 months for SCR – are only "reasonable expectations for sources that have completed most of their preliminary project planning and can quickly make commitments to proceed." 76 Fed.

Reg. 48,282. Applying this standard, EPA's schedule assumptions would be *unreasonable* for the vast majority of unscrubbed coal-fired plants today, because "only about 30 gigawatts (GW) of the 143 GW of unscrubbed coal-fired power capacity (or about 22%) is currently under development or construction". *See* Standard & Poor's, Global Credit Portal Ratings Direct, at 5. Consistent with this view, some utilities have already asserted that EPA has underestimated the time required to install dry or wet scrubber technology, arguing that installation of a scrubber system can take up to 52 months – i.e., nearly twice as long as EPA projects. *Id.* at 6.

In the context of developing its proposed Utility MACT, EPA acknowledged that the same class of affected sources would face material challenges in completing significant emission control systems by November 2015 (the date currently identified by EPA as the probable compliance date under the Utility MACT for existing sources) – nearly two years after the initial compliance date for Phase II of CSAPR. 76 Fed. Reg. 25,054-55.[8] EPA cannot simultaneously conclude that affected utilities will require *four years* to install the necessary controls to demonstrate compliance with the Utility MACT, but only *two-and-a-half years* to install the *same* types of complex controls to demonstrate compliance with CSAPR. Indeed, EPA apparently recognizes that many facilities will not be able to satisfy the Phase II requirements through the installation of controls and, on this basis, effectively *relies* on banking as a compliance option as a basis to justify the timing of the Phase II requirements under CSAPR. *See* EPA, Office

[8] In the context of the Utility MACT, as part of EPA's "analysis to assess the feasibility (e.g., the ability of companies to install the required controls within the compliance time-frame) and potential impact of the proposed rule on reliability", the Agency "assessed a time-frame that would allow some installations to take up to 4 years. This time-frame is consistent with the CAA which allows permitting authorities the discretion to grant extensions to the compliance time-line of up to 1 year." 76 Fed. Reg. 25,054-55. Thus, it is clear that EPA fully expects that affected existing sources will require more than three years to demonstrate compliance with the final Utility MACT.

of Air and Radiation, Assurance Penalty Level Analysis Final Rule TSD, Docket ID No. EPA-HQ-OAR-2009-0491 (2011), at 5 (EPA's recognizes that "[c]overed sources in [SO_2 Group 1 states] may decide to reduce their emissions further than required in 2012 and 2013 and bank the unused allowances for use in 2014 and later years. This pattern effectively smoothes their emission reductions over time to minimize total compliance costs in those states.").

For these reasons, ARIPPA believes CSAPR's current Phase II applicability date is improperly aggressive. ARIPPA requests that the Agency revise the relevant applicability provisions under CSAPR such that Phase II does not commence until January 1, 2016. That is, in order to achieve consistency with the probable schedule for implementation of the Utility MACT, affected sources under CSAPR should be given four years from the anticipated promulgation date of the final Utility MACT rule to demonstrate compliance with Phase II – i.e., November 2015. Because CSAPR is currently structured to apply on a calendar-year basis, ARIPPA recommends that Phase II commence at the start of the first calendar year following November 2015 – i.e., January 1, 2016. Phase I should commence two years prior to Phase II, as currently intended by EPA; therefore, Phase I would commence on January 1, 2014.

D. EPA's promulgation of a FIP under CSAPR *prior* to allowing states the opportunity to develop their own programs to address interstate pollution transport is contrary to CAA Section 110.

EPA apparently acknowledges that individual states may face unique circumstances in implementing CSAPR that are most appropriately addressed at the state-level in determining the most effective implementation of the overall regulatory objectives. Indeed, EPA ultimately affords each state the opportunity to develop a state implementation plan ("SIP") to allocate the state allowance budget in the manner deemed most appropriate by the state, and implement the overall CSAPR regulatory scheme within certain established bounds. This approach appropriately recognizes that facility-specific considerations, that are more difficult to evaluate at the national level, can be taken into account by each state in formulating its CSAPR compliance strategy. Further, the allocation scheme devised by each state can reflect critical policy considerations and electricity reliability concerns.

Against this backdrop, EPA's decision to directly promulgate a federal implementation plan ("FIP") is very surprising, and runs the risk of severely undermining the potential for a strategic balancing of emission control objectives with preservation of energy reliability and other important policy considerations. In fact, EPA's approach does not appear to be consistent with the mandates of the CAA. Section 110(a)(1) of the CAA directs the states to "adopt and submit to the [EPA], . . . after the promulgation of a national . . . ambient air quality standard [("NAAQS")] . . . a plan which provides for implementation, maintenance, and enforcement of such [NAAQS] . . . within such State." 42 U.S.C. § 7410(a)(1). Therefore, in the normal course, in accordance with the CAA, *the states* are tasked with the responsibility of developing a plan – i.e., a State Implementation Plan ("SIP") – that demonstrates how the state will attain and maintain compliance with the any NAAQS promulgated by EPA. By contrast, the CAA limits EPA's authority to promulgate a "FIP" to address the NAAQS to two specific situations: (1) where EPA finds that a state has failed to make a required SIP submission (or the SIP submitted fails to meet the minimum criteria required under Section 110); or (2) where EPA disapproves a SIP in whole or in part. 42 U.S.C. § 7410(c)(1). Even in these situations, EPA may not promulgate a FIP if the state corrects the deficiency and the Agency approves the revised SIP. *Id.* Importantly, CAA Section 110(c)(1) is based on the premise that the states were actually given the opportunity to develop SIPs in the first instance – i.e., *before* EPA promulgated a FIP.

According to EPA, the purpose of CSAPR is to limit the interstate transport of SO_2 and NOx emissions that affect the ability of downwind states to attain and maintain compliance with the NAAQS for fine particulate matter ("PM2.5") and ozone. 76 Fed. Reg. 48,208. Notwithstanding the language of CAA Section 110, in the case of CSAPR, EPA has promulgated a FIP as the first step in addressing the interstate transport of emissions that may cause or contribute to an exceedance of the NAAQS for PM2.5 and ozone in downwind states. In addition, EPA's prior efforts to regulate interstate air pollution – i.e., the NOx SIP Call and CAIR – both properly allowed the states the opportunity to develop their own plans in response to the new regulations, rather than issuing a FIP as the first step in the implementation of the regulatory program, as EPA has done in the instant case of CSAPR.

In order to ensure consistency between CSAPR and the CAA, EPA should delay the effective date of Phase I of the final rule to allow states sufficient time to develop SIPs to address the emission reduction goals identified in the final regulation through their own state-specific programs. In the event that a state fails to submit a SIP (or submits an incomplete SIP), or EPA disapproves the SIP, and the state does not remedy the deficiency, then the provisions of CSAPR FIP would become effective in the relevant state(s).

VI. Conclusion

As explained above, CSAPR should not apply to ARIPPA's coal refuse-fired CFB boilers, because EPA has not justified a finding of significant contribution as to these units. Despite EPA's clear recognition that there are multiple source categories responsible for significant generation of NOx and SO_2 emissions, EPA concluded that the objectives of CSAPR can most cost-effectively be achieved by regulating only EGUs. However, EPA failed to distinguish among EGUs within CSAPR, including on the basis of emissions characteristics, fuel source, operational design, emissions control options, or any other criteria. That is, CSAPR applies to any stationary fossil fuel-fired boiler or combustion turbine qualifying as an EGU under the final rule. This approach is inappropriate and results in unsupportable applicability determinations, particularly with respect to the ARIPPA facilities, which exhibit certain fundamentally distinct characteristics relative to EGUs.

The CFB units used by the ARIPPA plants exhibit unique characteristics that distinguish them from traditional EGUs. These distinct emission control characteristics are significant with respect to CSAPR, in that the emission control technologies considered by EPA for application to EGUs under CSAPR do not readily extend to CFB technology However, EPA's cost-effectiveness analysis under CSAPR fails to account for these significant distinctions in coal refuse-fired CFB units, and, therefore, EPA's determination that EGUs can be cost-effectively controlled consistent with the objectives of CSAPR does not, in fact, apply to the CFB technology used by the ARIPPA facilities. ARIPPA's analysis of the relative cost-effectiveness of the compliance options theoretically available to ARIPPA plants for reducing SO_2 emissions demonstrates that neither DSI nor SDA are both technically and economically available to the ARIPPA plants for reducing SO_2 emissions to the levels required under CSAPR in 2014.

The reduction in the SO_2 emission budgets for Pennsylvania and other states from the proposed Transport Rule to the final regulation constitutes a fundamental change for which EPA has not provided sufficient notice or opportunity for comment or adequate support. Notwithstanding the significant differences in the state budgets between the final rule and the version originally proposed, as clearly recognized by the OMB, EPA did not provide interested parties with an opportunity to comment on the revised budgets before incorporating them into the final rule and, on this basis, violated the applicable provisions of the APA governing proper notice and comment procedures. Likewise, EPA also failed to provide adequate justification supporting the significant reductions in the SO_2 budgets for Pennsylvania and other states. EPA should therefore reconsider CSAPR on this basis, and provide affected sources and states an adequate opportunity to review and comment upon the revised state emission budgets.

The timing of the effectiveness of CSAPR will make it impossible for certain sources to demonstrate compliance by the applicable deadlines. EPA recognizes that affected sources will not be able to install advanced post-combustion controls before 2012. Instead, EPA believes sources can achieve the Phase I reductions by operating existing controls, fuel switching, and/or increasing dispatch of lower-emitting generation. However, for many facilities, like the ARIPPA plants, it is infeasible, due to technical limitations and other restrictions, to engage in fuel switching or rely on lower-emitting units. In this way, CSAPR effectively requires certain facilities to pay other facilities for the continued right to operate – a regulatory scheme EPA has not previously implemented, as such a scheme is clearly not authorized under the CAA.

In order to avoid this result, ARIPPA requests that the Agency revise the final rule to afford affected facilities a reasonable opportunity to implement the measures necessary to reduce emissions. Specifically, EPA should postpone the applicability date for Phase I until January 1, 2014, consistent with EPA's proposed timing for the implementation of the Utility MACT.

Finally, EPA's direct promulgation of a FIP under CSAPR prior to allowing states the opportunity to develop their own programs to address interstate pollution transport is inconsistent with the mandates of the CAA. Accordingly, to ensure consistency between CSAPR and the CAA and provide for a sufficient time for facilities to achieve compliance, EPA should delay the effective date of Phase I of the final rule to afford states sufficient time to develop SIPs to address the emission reduction goals identified in the final regulation through their own state-specific programs.

ARIPPA appreciates the opportunity to submit this Petition for Reconsideration and looks forward to continuing to work with EPA to address the issues discussed herein. Should you have any questions or need any additional information in considering the information presented above, please contact the undersigned.

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Attachment A

Estimated Cost of SO2 Control for Waste Coal CFBs

In the development of CSAPR, EPA determined that $2,300/ton was the threshold for cost effective controls of SO2 in Group 1 states and concluded that this expenditure would reduce 2014 base case emissions by about 70 percent. By this determination, EPA apparently has concluded that the waste coal power plants affected by this rule can reduce SO2 emissions in a cost effective manner. This conclusion is not supported (or even addressed) in EPA's analysis and is demonstrably false for several different reasons, as presented below and in the following tables.

As detailed in ARIPPA's Petition for Reconsideration accompanying this Attachment, the only viable option for additional SO2 control to meet the emission reductions required in Phase II is the installation of an advanced back-end control device. In the context of EPA's Utility MACT, EPA apparently assumed that Dry Sorbent Injection ("DSI") is an available technology for the reduction of SO2 and acid gas emissions from waste coal plants, despite the fact that no application of DSI to a waste coal circulating fluidized bed ("CFB") boiler has ever been demonstrated. The basis for assuming the availability and utility of DSI was apparently the result of a single presentation at a technical symposium given by a supplier of chemical sorbents. There were no data cited by EPA (nor to our knowledge do any exist) demonstrating that a plant controlling more than 90% of its SO2 emissions through limestone addition can achieve another 70% reduction through injection of DSI. Nonetheless, even assuming that DSI can be used to achieve compliance with CSAPR, it is highly unlikely that SO2 can be controlled at a cost anywhere close to $2,300/ton.

An evaluation of the potential control costs for DSI for a typical 80 MW waste coal CFB was undertaken using a template that was developed for EPA's IPM Model by Sargent & Lundy.[1] The results of this analysis (as shown in Table A-1) is that the SO2 control cost will exceed $3,300/ton, which is considerably greater than the EPA cost effectiveness threshold of $2,300/ton. It is likely that this is the best case, in that it assumes that DSI will actually provide the required emission reductions at a trona injection rate (NSR of 2.5) projected by a DSI system vendor. However, recent applications of DSI (both permanent and test applications) on conventional coal fired boilers and a biomass CFB unit have required much higher trona injection rates in practice than were originally anticipated to achieve emission reduction targets. Some applications have required trona injection rates to be at a NSR of 6 to 8 compared to initial estimates of 1.5 to 2.0. At these increased injection rates, the control costs of DSI would likely be in excess of $6,400 per ton of SO2 removed, as shown in Table A-2.

A further concern with DSI is the potential impact of the injection of a sodium-based sorbent on ash quality. Recent testing has shown that use of trona for SO2 control at

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[1] Source: Sargent & Lundy, LLC. IPM Model - Revisions to Cost and Performance for APC Technologies. Dry Sorbent Injection Cost Development Methodolgoy. Final Report. August 2010. Project 12301.007.

coal-fired power plants can result in significantly increased leaching of sodium, sulfate, chloride, fluoride, arsenic, and selenium.[2] Most waste coal plants currently provide their ash for beneficial use in abandoned mine reclamation. However, if the use of trona produces changes in ash quality that cause the exceedance of beneficial use criteria, then this practice could be eliminated. In such an event, the ash would then need to be disposed of in lined landfills at a tipping fee of approximately \$28/ton to \$40/ton. For an 80 MW plant, this would represent an additional annual operating cost of \$14,000,000 to \$20,000,000, without accounting for potential increases in transportation costs. This would then raise the cost of SO2 control from a minimum, "best case" cost of \$3,300/ton removed to at least \$11,500/ton removed, which is far greater than EPA's threshold for cost effective controls and is clearly not economically feasible for the ARIPPA plants.

Another possibility is that DSI could be found to not be capable of achieving the emission reductions required by the waste coal CFBs. In this case, a separate, tail end emission control system would need to be implemented. One likely candidate would be a spray dryer absorber ("SDA"). The installed cost of an SDA system retrofit on the typical 80 MW ARIPPA plant was estimated using a template developed for EPA's IPM Model by Sargent & Lundy for this technology.[3] As shown in Table A-3, the estimated SO2 control costs of using a retrofit SDA is \$8,942/ton, which is nearly four times greater than EPA's cost effectiveness threshold.

[2] Su, T., Shi, H., and J. Wang, 2011. Impact of Trona-Based SO_2 Control on the Elemental Leaching Behavior of Fly Ash. *Energy Fuels*, **2011**, *25* (8), pp 3514–3521.

[3] Source: Sargent & Lundy, LLC. IPM Model - Revisions to Cost and Performance for APC Technologies. SDA FGD Cost Development Methodolgoy. Final Report. August 2010. Project 12301.007

Table A-1
Estimated Costs of SO2 Control Using DSI to Comply with Phase II SO2 Allowance Limits (Trona Injection at NSR = 2.5)

Variable	Designation	Units	Value	Calculation
Unit Size (gross)_	A	(MW)	80	
Retrofit Factor	B		1	
Gross Heat Rate	C	(Btu/KWh)	12000	
SO2 Rate	D	(lb/MMBtu)	0.6	Current Emission Rate with Limestone Injection
Type of Coal	E		Waste Gob	
Particulate Capture	F		Baghouse	
Milled Trona	G		TRUE	
Removal Target	H	Percent	70	Percent reduction to get from 0.60 to 0.18 lb/MMBtu
Heat Input	J	(Btu/hr)	9.60E+08	
NSR	K		2.5	Based on DSI Equipment Vendor Estimate
Trona Feed Rate	M	(ton/hr)	1.73	Equals (1.2011 x 10-6)*K*A*C*D
Auxiliary Power Requirement	Q	(%)	0.43	Equals M*20/A
Trona Cost	R	($/ton)	220	Based on delivered price to plant in Reading, PA
Aux. Power Price	T	($/kWh)	0.06	
Operating Labor Rate	U	($/hr)	60	

Capital Costs of DSI		
Capital Cost - DSI Base Module (BM)	$8,781,369	For Milled Trona; 7,516,000*B*(M^0.284)
Eng. & Contr. Management	$439,068	Equals 5% of BM Costs
Contractor Profit and fees	$439,068	Equals 5% of BM Costs
Total Capital, Eng, & Constr. Costs (CECC)	$9,659,505	
Owner's Costs, including project manage.	$482,975	Equals 5% of CECC
Total Capital Costs	**$10,142,481**	CECC plus Owner's Costs
Annualized Capital Costs	**$1,958,199**	Assumes 7-year financing @ 9% interest

Annual O&M Costs of DSI		
Cost of Trona	$3,166,592	M*R*8760*0.95; assumes 95% capacity factor
Cost of Auxiliary Power	$220,222	A*1000*Q*8760*0.95
Operating labor costs	$124,800	Assumres 1 FTE for operations; equals 2080*U
Maintenance material and labor costs	$87,814	Per S&L Equation; BM*0.01, i.e, 1% of base module costs
Total Annual O&M Costs	$3,599,427	

Total Annualized Costs of Control	
Capital Costs	$1,958,199
O&M Costs	$3,599,427
Total Annualized Costs	**$5,557,626**
SO2 Emission Reduction (tons)	1678
Cost of Control ($/ton SO2)	**$3,313**

Source: Sargent & Lundy, LLC. IPM Model - Revisions to Cost and Performance for APC Technologies. Dry Sorbent Injection Cost Development Methodolgoy. Final Report. August 2010. Project 12301.007

Table A-2
Estimated Costs of SO2 Control Using DSI to Comply with Phase II SO2 Allowance Limits (Trona Injection at NSR = 6)

Variable	Designation	Units	Value	Calculation
Unit Size (gross)_	A	(MW)	80	
Retrofit Factor	B		1	
Gross Heat Rate	C	(Btu/KWh)	12000	
SO2 Rate	D	(lb/MMBtu)	0.6	Current Emission Rate with Limestone Injection
Type of Coal	E		Waste Gob	
Particulate Capture	F		Baghouse	
Milled Trona	G		TRUE	
Removal Target	H	Percent	70	Percent reduction to get from 0.60 to 0.18 lb/MMBtu
Heat Input	J	(Btu/hr)	9.60E+08	
NSR	K		6	Based on Recent DSI Applications
Trona Feed Rate	M	(ton/hr)	4.15	Equals (1.2011 x 10-6)*K*A*C*D
Auxiliary Power Requirement	Q	(%)	1.04	Equals M*20/A
Trona Cost	R	($/ton)	220	Based on delivered price to plant in Reading, PA
Aux. Power Price	T	($/kWh)	0.06	
Operating Labor Rate	U	($/hr)	60	

Capital Costs of DSI		
Capital Cost - DSI Base Module (BM)	$11,260,099	For Milled Trona; 7,516,000*B*(M^0.284)
Eng. & Contr. Management	$563,005	Equals 5% of BM Costs
Contractor Profit and fees	$563,005	Equals 5% of BM Costs
Total Capital, Eng, & Constr. Costs (CECC)	$12,386,109	
Owner's Costs, including project manage.	$619,305	Equals 5% of CECC
Total Capital Costs	**$13,005,414**	CECC plus Owner's Costs
Annualized Capital Costs	**$2,510,942**	Assumes 7-year financing @ 9% interest

Annual O&M Costs of DSI		
Cost of Trona	$7,599,820	M*R*8760*0.95; assumes 95% capacity factor
Cost of Auxiliary Power	$528,533	A*1000*Q*8760*0.95
Operating labor costs	$124,800	Assumres 1 FTE for operations; equals 2080*U
Maintenance material and labor costs	$112,601	Per S&L Equation; BM*0.01, i.e, 1% of base module costs
Total Annual O&M Costs	$8,365,754	

Total Annualized Costs of Control	
Capital Costs	$2,510,942
O&M Costs	$8,365,754
Total Annualized Costs	**$10,876,696**
SO2 Emission Reduction (tons)	1678
Cost of Control ($/ton SO2)	**$6,483**

Source: Sargent & Lundy, LLC. IPM Model - Revisions to Cost and Performance for APC Technologies. Dry Sorbent Injection Cost Development Methodolgoy. Final Report. August 2010. Project 12301.007

Table A-3
Estimated Costs of SO2 Control Using SDA to Comply with Phase II SO2 Allowance Limits

Variable	Designation	Units	Value	Calculation
Unit Size (gross)_	A	(MW)	80	
Retrofit Factor	B		1	
Gross Heat Rate	C	(Btu/KWh)	12000	
SO2 Rate	D	(lb/MMBtu)	0.6	Current Emission Rate with Limestone Injection
Type of Coal	E		Waste Gob	
Particulate Capture	F		Baghouse	
Removal Target	H	Percent	70	Percent reduction to get from 0.60 to 0.18 lb/MMBtu
Heat Input	J	(Btu/hr)	9.60E+08	
NSR	K		1.5	From S&L Report
Lime Feed Rate	M	(ton/hr)	1.80	From S&L Report for 162 MW unit adjusted to 102 MW unit size
Auxiliary Power Requirement	Q	(%)	1.65	From S&L Report
Lime Cost	R	($/ton)	135	From S&L Report
Aux. Power Price	T	($/kWh)	0.06	
Operating Labor Rate	U	($/hr)	60	

Capital Costs of SDA

Capital Cost - SDA Retrofit	$40,000,000	From S&L Report; $500/kw for retrofit
Eng. & Contr. Management	$4,000,000	Per S&L Report; Equals 10% of BM Costs
Construction Labor	$4,000,000	Per S&L Report; Equals 10% of BM Costs
Contractor Profit and fees	$4,000,000	Per S&L Report; Equals 10% of BM Costs
Total Capital, Eng, & Constr. Costs (CECC)	$52,000,000	
Owner's Costs, including project manage.	$2,600,000	Per S&L Report: Equals 5% of CECC
Total Capital Costs	**$54,600,000**	CECC plus Owner's Costs
Annualized Capital Costs	**$10,541,567**	Assumes 7-year financing @ 9% interest

Annual O&M Costs of SDA

Cost of Lime	$2,022,246	M*R*8760*0.95; assumes 95% capacity factor
Cost of Auxiliary Power	$840,356	A*1000*Q*8760*0.95
Operating labor costs	$998,400	Per S&L report; Assumres 8 FTE for operations; equals 2080*U
Maintenance material and labor costs	$600,000	Per S&L Equation; BM*0.015, i.e, 1.5% of base module costs
Total Annual O&M Costs	$4,461,002	

Total Annualized Costs of Control

Capital Costs	$10,541,567
O&M Costs	$4,461,002
Total Annualized Costs	**$15,002,569**
SO2 Emission Reduction (tons)	1678
Cost of Control ($/ton SO2)	**$8,942**

Source: Sargent & Lundy, LLC. IPM Model - Revisions to Cost and Performance for APC Technologies. SDA FGD Cost Development Methodolgoy. Final Report. August 2010. Project 12301.007