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INDEPENDENT REGULATORY
REVIEW COMMISSION

August 25, 2006

Environmental Quality Board
P.O. Box 8477
Harrisburg, PA 17105-8477

Ladies and Gentlemen:

Re: Proposed Rulemaking Environmental Quality Board [25 PA CODE CH. 123] Standards for Contaminants; Mercury.

Attached are comments filed by PPL Generation, LLC on the proposed mercury rulemaking that was published in the Pennsylvania Bulletin on June 24, 2006.

PPL Generation, LLC is an indirect subsidiary of PPL Corporation. Subsidiaries of PPL Generation, LLC own two coal-fired generating stations (Brunner Island Steam Electric Station and Montour Steam Electric Station) that will be affected by the final mercury rule[1].

PPL recognizes that the Board has proposed this rule to address two inter-related concerns: (1) that no mercury reductions will be made in Pennsylvania if trading of mercury allowances are allowed; and (2) that this will create "hot spots" of mercury deposition. PPL believes, however, that real and substantial reductions, will in fact, be made even absent the proposed rule and, in any event, the proposed rule does not take the right approach to ensuring that reductions necessary to address the Department's "hot spot" concerns are made.

We believe that substantial reductions will be made even absent the proposed rule because all large power units greater than 250 MW either have wet SO2 scrubbers, have committed to install scrubbers (and installations are underway), or are expected to have scrubbers installed in 2008-2012. Scrubbers are state-of-the-art technology for removing oxidized mercury.

Even if further assurance were needed to ensure that substantial reductions are made in Pennsylvania, we believe the proposed regulation does not take the right approach because it fails to recognize that controlling oxidized mercury accomplishes the same level of deposition reduction in Pennsylvania as controlling total mercury emissions. In its comments, PPL is submitting modeling results that clearly show this. By focusing on reductions in total mercury and prohibiting trading, the proposed regulation will provide no additional environmental benefit

---

[1] A subsidiary of PPL Generation, LLC owns a third generating station (the Martins Creek station) with two coal-fired generating units that will be decommissioned before the effective date of the final regulation and will therefore not be affected by it.

over CAMR, but will result in significant costs for the entire Commonwealth and may well put the Commonwealth at risk of not being able to meet its obligations under CAMR.

We hope you will take a careful look at our comments and, if you conclude that regulation beyond CAMR is required, we urge you to seriously focus on controlling oxidized mercury rather than total mercury emissions. In addition to avoiding unnecessary energy-cost-increasing expenditures, this approach also will avoid placing additional burdens on generating units that burn bituminous coal. We look forward to discussing this approach with you in greater detail.

Recognizing our comments are extensive, we have also attached a one page summary of our comments to be provided to each member of the Board in the agenda packet distributed prior to the meeting at which the final rulemaking will be considered. Included in our comments are the following documents:

1. One page summary, "Summary of Comments of PPL Generation, LLC Regarding Proposed Rulemaking Regulating Mercury Emissions"
2. A comment brief, "Comments of PPL Generation, LLC in the matter of Proposed Rulemaking Regulating Mercury Emissions from Electric Generating Units (Standards for Contaminants; Mercury) 36 PaB 3185 (June 24, 2006) August 25, 2006
3. An Evaluation of Deposition in Pennsylvania for Potential Mercury Emission Reduction Strategies Prepared for PPL Generation, LLC prepared by ENVIRON International Corporation Emeryville, California, August 25, 2006.
4. An Evaluation of Mercury Emissions Reductions in Pennsylvania prepared for PPL Generation, LLC, by URS Fort Washington, Pennsylvania, August 25, 2006.
5. An Evaluation of Alternative Approaches to Reducing Pennsylvania Mercury Emissions, Prepared for PPL Generation, LLC by NERA Economic Consulting Boston, Massachusetts August 25, 2006
6. Supplemental comments on proposed Title 25, Part I, Subpart C, Article III, Chapter 123 Standards For Contaminants – Mercury Emissions filed by PPL Generation, LLC August 25, 2006

We look forward to meeting with you soon.

Very truly yours,

Robert J. Barkanic P. E.
Director-Environmental Management
PPL Services Corporation

Attachments

SUMMARY OF COMMENTS OF PPL GENERATION, LLC REGARDING PROPOSED RULEMAKING REGULATING MERCURY EMISSIONS

The Board Should Revise the Proposed Rule if the Board concludes that a state-specific rule is needed. The Board should revise the Proposed Rule to (i) incorporate CAMR with unrestricted trading; and (ii) require a specified level of control of *oxidized* mercury at Pennsylvania EGUs.

A state specific rule is not necessary for hot spots and even if necessary, the proposed rule is not the right approach. The Board has not justified the need for a state-specific rule. No analysis has been done in support of its concern for hot spots or to determine whether emission reductions expected under other programs would be sufficient to address the concern even if valid. Further, the Board's approach does not address the concern in the correct way. The Board itself recognizes that current emissions of mercury from Pennsylvania's EGUs are both in an _oxidized_ and _elemental_ form. The _oxidized_ mercury deposits in the Commonwealth, whereas _elemental_ mercury travels in the atmosphere for up to a year as part of a larger global pool. Deposition modeling performed for PPL by ENVIRON Corporation confirms that elemental mercury emissions from Pennsylvania EGUs have no discernible impact on mercury deposition in the state and only reductions in emissions of *oxidized* mercury affects deposition. In fact, requiring EGUs to go further to capture elemental mercury could prove to be counterproductive since elemental mercury must first be oxidized to remove it and capture is not 100%. Accordingly, the Board should ensure that Pennsylvania EGUs control their emissions of *oxidized* mercury in order to address the deposition and "hot spot" issue. Additional constraints on allowance trading to comply with the state budget allocation for total mercury provide no additional benefit.

The Board has grossly underestimated the cost of implementing the Proposed Rule. The Board erroneously based its cost estimates on a 90% emission reduction and overlooked the cost necessary to obtain the 95% or greater reductions required to achieve the CAMR-based annual allowance limit without trading. As explained in the report prepared for PPL by URS Corporation, the costs *per unit* to comply with the annual limit are projected to exceed the cost the Board projected for *all EGUs combined*. Scrubbers installed to comply with CAIR are state-of-the-art controls with at least a 90% control efficiency for oxidized mercury. As explained in NERA's report for PPL, Pennsylvania EGUs will likely go even further to optimize their controls to capture elemental mercury as well under CAMR. But requiring that the Pennsylvania EGUs obtain every last increment of elemental mercury reduction to meet the total mercury allowance will add tremendous costs without producing any benefit for Pennsylvania.

The Proposed Rule harms bituminous coal. The CAMR budgets already penalize bituminous coal and the Proposed Rule imposes an additional burden without benefit. The presumptive technologies designed to benefit bituminous coal will not achieve compliance with the CAMR-based annual emissions limit. Even after EGUs burning bituminous coal control oxidized mercury to eliminate any contribution to deposition or hot spots in Pennsylvania, the Proposed Rule would require that they install additional controls at whatever cost it takes to capture enough elemental (and thus total) mercury to comply with their allowance allocations.

Pennsylvania may well end up unable to comply with CAMR. The annual emissions caps that each EGU must meet without trading are extremely stringent. In Phase I, the cap would require total mercury reductions from the mercury in the bituminous coal supply in the range of 88% to 90%, and in Phase II the cap would require reductions in the range of 95% to 98%. As elaborated in the URS Report, achieving these reductions might not only be expensive but might well be infeasible. As there is no basis to believe surplus allowances will be available in the state to make up the shortfall, Pennsylvania may well end up unable to comply with its CAMR budget allocation. This would surely be at great cost and possibly lead to the undesired result of *increasing* total national mercury emissions.

* * *

Supplemental Comments of PPL Generation, LLC

in the matter of

Proposed Rulemaking Regulating

Mercury Emissions from Electric Generating Units
(Standards for Contaminants; Mercury)
36 Pa.B. 3185 (June 24, 2006)

submitted to

The Pennsylvania Environmental Quality Board
Rachel Carson State Office Building
15th Floor, 400 Market Street
Harrisburg, Pennsylvania 17101-2301

August 25, 2006

SUPPLEMENTAL COMMENTS ON PROPOSED TITLE 25, PART I, SUBPART C, ARTICLE III, CHAPTER 123

STANDARDS FOR CONTAMINANTS – MERCURY EMISSIONS

These supplemental comments address various issues associated with Pennsylvania's proposed regulations regarding mercury emissions. In particular, these comments recommend specific revisions to the language of the Proposed Rule in its current form in the event that the Pennsylvania Environmental Quality Board (the "Board") adopts a rule that is substantially similar. These suggested revisions are provided in addition to, and not in lieu of, PPL's formal written comments in order to preserve any and all arguments relating to this rulemaking process. However, PPL's overall position remains that the Board should implement the federal Clean Air Mercury Rule (CAMR) to comply with the federal budget allocation for total mercury, and address Pennsylvania-specific concerns by focusing on oxidized mercury as an overlay to CAMR.

The following comments are presented in the order in which the provisions at issue appear in the proposed regulations.

I. THE ANNUAL EMISSION LIMIT SUPPLEMENT POOL IS OF LIMITED VALUE TO EGUS.

While this supplement pool has been developed to provide for statewide averaging and/or trading as a means to address the CAMR budget issues, if a unit does not meet the annual limit specified by Section 123.207, it is actually of limited value to affected units. For business planning purposes, a unit must be certain that it can comply with the annual emission limitation. That can mean that units will be forced no longer to consider some Pennsylvania coal supplies, or that a unit which cannot assure compliance will be unable to obtain financing to fund additional controls.

II. PROVISIONS OF SECTION 123.205 SETTING FORTH PERCENT EMISSION REDUCTION REQUIREMENTS SHOULD INCLUDE AN OPTION TO BE BASED ON "AS-MINED" COAL.

Section 123.205 bases compliance with the mercury percentage reduction requirements on "as-fired" coal. Mercury removed in coal preparation should definitely be credited for meeting the percent reduction requirements. EPA's mercury budget for Pennsylvania requires an 86% reduction in 2018 (Pennsylvania's rule would require this in 2015) from 1999 emission levels, not from mercury in the coal. The rule should allow credit for any reductions in mercury that are achieved through coal cleaning/preparation.

III. SECTION 123.205 (D) AND (E) SHOULD BE BASED ON ANNUAL AVERAGES, NOT ROLLING 12-MONTH AVERAGES.

Section 123.205 (d) and (e) bases compliance with energy output-based emission standards and mercury percentage reduction requirements on rolling 12-month averages. Instead, these standards should be on an annual basis, similar to EPA's Acid Rain Program and NO_x Budget Program and CAMR. Requiring calculations to be made on a rolling 12-month average is unnecessary and would entail needless administrative burdens.

IV. SECTION 123.207 (C) SHOULD STATE THAT NEW EGUS SHOULD RECEIVE ALLOCATIONS EQUAL TO THEIR ACTUAL EMISSIONS.

Section 123.207 (c) specifies that the Department will establish the allocation for new EGUs during the plan approval or operating permit process, but nothing in this section lays out how that allocation is to be determined. The rule should require that new sources receive an allocation equal to their actual emissions.

V. SECTION 123.207(C)(2) SHOULD PROVIDE THAT UNUSED ALLOWANCES FROM THE NEW SOURCE "SET ASIDE" PROGRAM SHOULD BE DISTRIBUTED AMONGST EXISTING UNITS.

Emission allowances withheld from an existing source that are not needed for new sources, should be returned to the source from which they are withheld. Placing the unused allowances in the emission limit supplement pool could cause those allowances to be made available to a generator that exceeds its initial set aside amount. Such a result would be inequitable.

VI. SECTION 123.207 (9) SHOULD REQUIRE THAT SET-ASIDE AMOUNTS FOR EXISTING SOURCES SHOULD BE PUBLISHED AS EXPEDITIOUSLY AS POSSIBLE

Data needed for establishing set-aside amounts for existing sources – that is, base year heat input and the Pennsylvania mercury allowance allocation – is fixed and available. There is no need to wait until July 1, 2009 to publish this information. The sooner sources know their allocations the better they can plan to try to meet those allocations. Similarly, the Phase II allocations should be made well in advance of the July 1, 2014 date proposed.

VII. SECTION 123.207 (J) SHOULD REQUIRE THE DEP TO NOTIFY EGUS ABOUT ALLOWANCE AWARDS MUCH EARLIER THAN IS CURRENTLY CALLED FOR.

Under Section 123.207(j), a generator will not know if it is able to obtain allowances that it needs to comply with emission limitations until after it could already be in a noncompliant situation. For example, if a generator learns late in the year that, under normal operations, it may exceed its number of allowances, there would be no assurance that allowances could be obtained from the supplement pool. In this situation, a generator whose policy is to comply with all environmental regulations would be forced to suspend generation until the following year. Such a situation would likely lead to reliability problems with the electric supply.

VIII. SECTION 123.207 (J)(2) SHOULD BE REVISED TO PERMIT OWNERS OF MULTIPLE EGUS TO UTILIZE THEIR UNUSED ALLOWANCES AT ANY OF THEIR FACILITIES.

Section 123.207 (j)(2) mandates that the DEP withhold from EGUs any unused portions of their emission allowances. Such a requirement provides no incentive to install more effective emission controls so that allowances could be used for other units or perhaps even sold to other generators. Instead, a rule such as this will undoubtedly lead to very few allowances being made available for the state-managed averaging/trading program. This is especially true for the second phase of the Proposed Rule. This type of program would be better operated and managed by the EPA through CAMR, and the individual generators implementing the controls.

IX. SECTION 123.207 (J)(3) SHOULD BE REVISED TO PERMIT BANKING OF UNUSED ALLOWANCES FOR SUBSEQUENT YEARS.

Section 123.207 (j)(3) prohibits unused allowances from being used in future years. This restriction should be removed to allow more flexibility in meeting emissions limits. Specifically, the ability to use banked allowances in subsequent years would accommodate the year-to-year variability in emissions that can be expected.

X. VIOLATIONS OF EMISSIONS STANDARDS SHOULD BE BASED ON MERCURY ALLOWANCES "AWARDED TO" A SOURCE, NOT ALLOWANCES "SET ASIDE FOR" A SOURCE.

As currently proposed in Section 123.207(j)(5), EGUs could be charged with emissions violations if they exceed the number of allowances "set aside," even if a source was granted additional allowances from the supplement pool to cover excess emissions. This should be clarified to avoid any confusion or an unfair result.

XI. SECTION 123.207(J)(5) SHOULD BE REVISED TO PROVIDE THAT EXCEEDING THE NUMBER OF EMISSION ALLOWANCES SHOULD ONLY CONSTITUTE A SINGLE VIOLATION.

Assessing a penalty for exceeding allowances in the aggregate is adequate incentive for source owners to comply with the regulation. Conversely, assessing penalties for incremental violations is overly punitive, especially for each *ounce* emitted in excess of the limits. At most, each *pound* of mercury emitted in excess of limitations should be considered a violation.

XII. SECTION 123.207 (L) SHOULD BE REVISED TO REQUIRE THE DEP TO MEET CERTAIN CRITERIA BEFORE INCREASING ALLOWANCES FOR NEW SOURCES.

Section 123.207(l) would allow the DEP, simply at its discretion, to increase the new source set-asides taken from existing sources. As presently proposed the size of the new source set-aside is larger than needed thereby imposing an undue burden on existing sources. Should the DEP have the authority to increase the size of the set-aside amounts, stringent criteria should be established that must be met before the DEP can take any action.

XIII. SECTIONS 123.209 (F) (1) THROUGH (7) REQUIRE THE SUBMISSION OF UNNECESSARY INFORMATION IN ORDER TO OBTAIN ALLOWANCES FROM THE ANNUAL EMISSION LIMIT SUPPLEMENT POOL.

Information required by Section 123.209 (f) (1) through (7) has no bearing on the process for requesting allowances from the supplement pool. Allowances are to be distributed in the order of preference determined by source configuration. The regulation properly excludes additional criteria to grant such a request. Therefore, Section 123.209(f) (1) through (7) is extraneous and constitutes an unnecessary administrative burden.

XIV. SECTION 123.209(G) SHOULD BE REVISED TO MAKE SET-ASIDE ALLOWANCES MANDATORY, NOT DISCRETIONARY.

As proposed, this section would allow the DEP to withhold set-aside allowances provided to a source based on its own discretion. Instead, the regulation should be revised to make set-aside allowances mandatory or, alternatively, to specify a number of factors that must be met prior to any withholding.

XV. SECTION 123.209 (G)(1) SHOULD BE REVISED TO PREVENT STAND-BY UNITS FROM RECEIVING FIRST PREFERENCE FOR ALLOWANCES FROM THE ANNUAL EMISSION LIMIT SUPPLEMENT POOL.

As currently proposed, stand-by units receive first priority for supplemental allowances, even if those stand-by units have no pollution control device configuration designed to remove mercury emissions. This is inconsistent with the preference hierarchy that orders configurations based on their presumed effectiveness for mercury removal. This preference is inequitable, thus, stand-by units should receive preference only to the extent that it is consistent with the pollution control equipment configuration in place at the unit.

XVI. SECTION 123.209(G) (7) SHOULD BE CLARIFIED IN ORDER TO KEEP PREFERENCES WITH REGARD TO CONTROL CONFIGURATIONS CONSISTENT.

While Sections 123.209 (g)(1) through (g)(6) list the six specific categories of pollution control equipment configurations in order of preference, Section 123.209(g)(7)appears to apply to all other configurations not included in Sections 123.209(g)(1) through (g)(6) This provision, however, does not set forth any criteria on which preferences for these "other configurations" could be determined. Although the Department could arbitrarily exercise its discretion in ordering the preference, however, that should not be permitted. Instead, all remaining configurations (which are not set forth in Sections 123.209(g)(1) through (g)(6) should have an equal opportunity for supplemental allowances. PPL recommends that this provision be revised to read:

> "Each owner or operator of an existing affected EGU not listed in subsections (1) through (6) above. If the emission limit supplement pool does not have enough allowances left to accommodate all such units, each unit should receive an allocation based on the ratio of its megawatt rating to the sum of megawatt ratings of all units in this category."

XVII. SECTION 123.210(E) SHOULD BE REVISED TO ACCOMMODATE UNITS THAT HAVE WET FLUE GAS DESULFURIZATION UNITS THAT WILL COMMENCE OPERATION AFTER MARCH 1, 2009.

Mercury emission monitors are installed downstream of wet flue gas desulfurization (WFGD) units, and if the WFGD does not commence until after March 1, 2009, the monitoring system will go untested. To accommodate this situation PPL recommends revising Section 123.201 (e) (2) to read as follows:

> "(2) Ninety EGU operating days or 180 calendar days, whichever occurs first, after the date on which the EGU commences commercial operation, <u>or after which a WFGD</u>

planned to commence operation before January 1, 2010 becomes operational, but in no event later than January 1, 2010."

XVIII. SECTION 123.210(F) (2) SHOULD BE REVISED TO ACCOMMODATE UNITS THAT HAVE WFGD UNITS THAT GO ONLINE AFTER MARCH 1, 2009.

Changes similar to those proposed above should be made to this section of the Proposed Rule as well.

XIX. SECTION 123.212 SHOULD BE REVISED TO PROVIDE THAT SUBSTITUTE DATA SHOULD BE USED ONLY TO MEET ANNUAL CAP REQUIREMENTS, NOT TO MEET RATE-BASED LIMITS.

Substitute data which are biased high should be used only in the computation of annual emissions, and should not be used to calculate the percentage of mercury removal. Only actual data should be used to calculate the percentage of mercury removal.

XX. SECTION 123.213 SHOULD BE REVISED TO REQUIRE MONITORING FOR GROSS ELECTRICAL OUTPUT ONLY FOR SOURCES THAT CHOOSE TO MEET THE EMISSION LIMIT BASED ON MASS OF MERCURY EMITTED PER UNIT OF ELECTRICAL OUTPUT.

Section 123.213 would require sources to monitor gross electrical output even if they do not opt for an output-based limit. However, gross electrical output does not enter into the calculation of percent mercury removal and therefore there is no need to require monitoring of gross electrical output for these sources.

XXI. SECTION 123.214 SHOULD BE REVISED TO EXPRESSLY ALLOW THE MERCURY LEVEL IN COAL "AS MINED" TO BE USED TO CALCULATE THE PERCENTAGE OF MERCURY REMOVAL.

As explained above, mercury removed in coal preparation may be entitled to receive a credit towards achieving the required reduction percentage if further testing supports this conclusion. EPA's mercury budget for Pennsylvania requires an 86% reduction in 2018 (Pennsylvania's rule would require this in 2015) from 1999 emission levels, not from mercury in the coal. The rule should allow credit for any reductions in mercury that are achieved through coal cleaning/preparation.

August 2006

An Evaluation of Alternative Approaches to Reducing Pennsylvania Mercury Emissions

Prepared for PPL Generation, LLC

NERA
Economic Consulting

MMC Marsh & McLennan Companies

Project Team

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About the Project Director

David Harrison, Jr., is a Senior Vice President of National Economic Research Associates, Inc. (NERA) in its Boston office (200 Clarendon Street, 35th Floor, Boston, MA 02116, +1-617-621-2612, david.harrison@nera.com) and head of NERA's global environmental economics practice. At NERA, Dr. Harrison has directed numerous studies related to energy and environmental issues. These studies include analyses of individual environmental regulations, air quality and climate change policy, and the use of emissions trading and other innovative policy approaches. He has served as a consultant in these and other areas to numerous public and private organizations.

Before joining NERA, Dr. Harrison was an Associate Professor at the John F. Kennedy School of Government at Harvard University, where he taught microeconomics, energy and environmental policy, and other subjects for more than a decade. He earlier served as Senior Staff Economist on the President's Council of Economic Advisors, where his areas of responsibility included energy and environmental regulation. Dr. Harrison is the author or co-author of four books and monographs, as well as many articles in professional journals. He received a Ph.D. in Economics from Harvard University, a M.Sc. in Economics from the London School of Economics, and a B.A. in Economics from Harvard College.

Executive Summary

Emissions trading has become an important mechanism to control air emissions in the United States. Experience over the past decades has shown that a well-designed and well-implemented cap-and-trade program can achieve air emissions targets at lower costs than the traditional command-and-control approach. Under a cap-and-trade program, total emissions are capped and sources are given the flexibility to trade emissions allowances, resulting in incentives to find and apply the lowest-cost methods for reducing emissions. Moreover, because total emissions are capped, there is greater certainty that emissions targets will be achieved. The flexibility of banking emission allowances and the ability to avoid increased emissions from certain plants where installing the required controls is infeasible also provide environmental advantages compared to a less flexible "command-and-control" approach.

A. Advantages of Cap-and-Trade as a Means to Control Mercury Emissions

The Clean Air Mercury Rule (CAMR) provides for states to meet their mercury budgets by allowing affected units within their jurisdictions to participate in an interstate emissions trading program for mercury. Experience with prior and existing emissions trading programs for other air emissions suggest that there would be substantial economic and environmental advantages to regulating mercury emissions through a cap-and-trade program as called for in CAMR.

- A cap on emissions that decreases over time provides strong incentives for early emission reductions through banking of excess allowances.
- To the extent that sources of mercury emissions have widely varying costs of control, there would be potential cost savings under the cap-and-trade approach.
- Trading provides a mechanism to manage uncertainties about the costs and effectiveness of control technologies, which could potentially be significant for controlling mercury emissions. Uncertainties regarding the likely mercury content of coal would also be managed more effectively with emissions trading.
- Trading encourages the development of new, more cost-effective control techniques.
- Trading also encourages facilities to get the most out of the technologies they install, since there is a continuous incentive to reduce emissions.

B. Concerns Raised by Proposed Pennsylvania Rule

1. Proposed Pennsylvania Rule

The proposed Pennsylvania mercury rule ("Pennsylvania Rule") does not allow Pennsylvania facilities to participate in a trading program for mercury. Instead, the Pennsylvania Rule requires Electricity Generating Units (EGUs) to meet one of three compliance requirements: (1) a generation-based emissions limit; (2) an emissions limit calculated as a percentage of mercury in the inlet coal; or (3) a probable control technology option. The Pennsylvania Rule also includes provisions that allow EGUs to apply for alternative emission standards on the basis that the Pennsylvania rule includes requirements that are "technologically or economically infeasible" (Pennsylvania EQB 2006). In addition to meeting one of the three criteria above, units must also comply with the CAMR allocations. Since the proposed Pennsylvania mercury rule does not allow any trading of mercury allowances, the CAMR allocations would function as unit-by-unit emissions limits, i.e., hard caps. These allocations are equivalent to requirements to capture 88-90 percent of inlet mercury in Phase 1 and about 96 percent of inlet mercury (or greater) in Phase 2, indicating that the CAMR allocations would be the most stringent aspect of the Pennsylvania Rule (URS, 2006). The Pennsylvania DEP has proposed this aggressive rule mainly in response to concerns over mercury "hotspots," or areas of high local deposition near Pennsylvania power plants.

2. Concerns Regarding the Costs and Benefits of the Proposed Pennsylvania Rule

The proposed Pennsylvania Rule raises four concerns related to the costs and benefits it would yield in Pennsylvania. Three of these concerns correspond to the numbered items in Figure ES-1, which illustrates these issues through a marginal abatement cost curve for a hypothetical Pennsylvania power plant. The total cost for reaching any level of mercury emissions (i.e.,

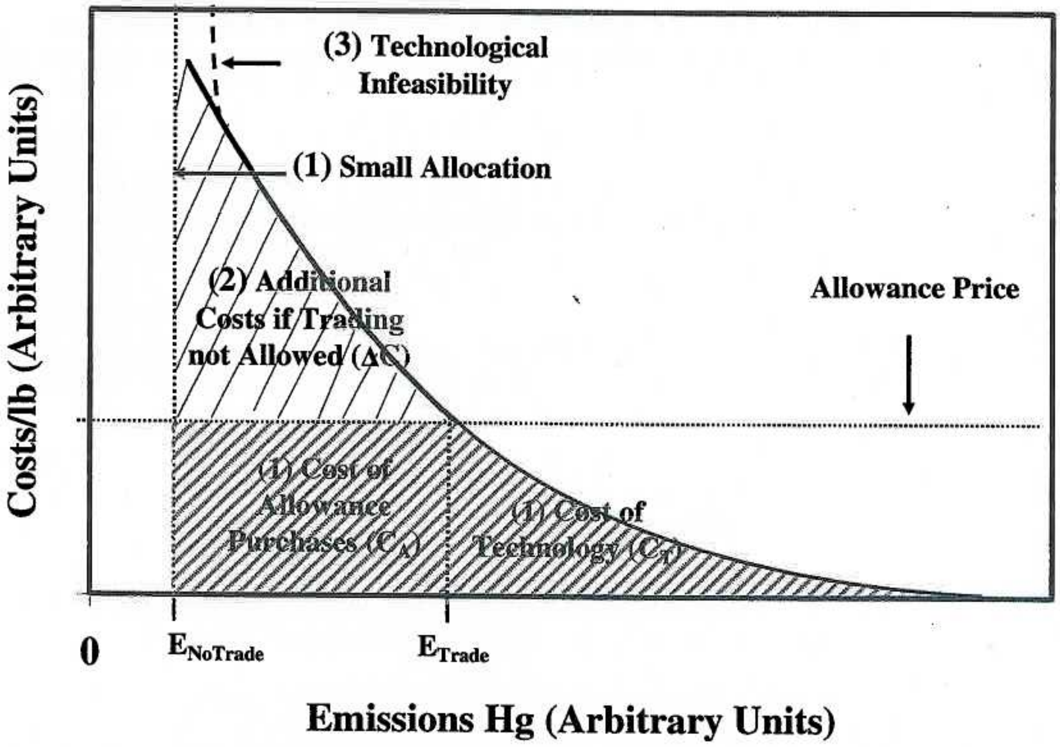

Figure ES-1. Illustration of several concerns raised by proposed Pennsylvania mercury rule. (1) small CAMR allocation; (2) additional compliance costs due to prohibition on emissions trading; and (3) a potential technical infeasibility due to the small allocation and the prohibition on trading.

reducing emissions below the "baseline" level) is shown as the area under the marginal cost curve. Under emissions trading, the cost per pound is limited by the allowance price. If emissions trading is not allowed, however, there is no limit to the cost per ton that the power plant could incur to reduce mercury emissions.

The four main concerns can be summarized as follows.

(1) *The Pennsylvania mercury budget under CAMR is small and thus compliance costs are large even with emissions trading.* CAMR requires substantial percentage reductions in mercury emissions, particularly for Pennsylvania units due to a coal-rank adjustment used by EPA in determining mercury allocations (see Section IV of this Report). The net effect of the stringent CAMR target and the adverse adjustment is large compliance costs for Pennsylvania units, even under emissions trading. (The area shaded in pink in Figure ES-1 illustrates the cost under CAMR with Pennsylvania's relatively small allocation.) Note that these high costs are a result of the CAMR allocation rather than the Pennsylvania Rule.

(2) *Disallowing emissions trading could raise compliance costs substantially.* The proposed Pennsylvania Rule does not allow emissions trading, and thus affected units must meet the CAMR allocations as a firm cap. Disallowing trading thus exacerbates the high costs to Pennsylvania units under CAMR, perhaps substantially. The area shaded in blue in Figure ES-1 illustrates the substantial additional costs to the Pennsylvania unit due to the prohibition on emissions trading under the Pennsylvania Rule. Note that these increased costs do not lead to any additional national mercury emission reductions; the prohibition on trading simply leads to higher compliance costs.

(3) *The CAMR Phase 2 allocations, if enforced as firm caps, may be technologically infeasible.* The Phase 2 allocation equates to approximately 96 percent (or greater) capture of mercury in inlet coal, a level that may be infeasible for some generating units given current technology (see URS 2006). The dashed line for the marginal cost curve in Figure ES-1 illustrates a case in which the illustrative Pennsylvania unit could not achieve the stringent cap on its own, regardless of the cost it incurs. Because the Pennsylvania Rule provides no flexibility for units that cannot meet their cap to purchase allowances from those that can over-control but does provide for alternative emission standards, this infeasibility on the part of some units may result in Pennsylvania exceeding its CAMR Phase 2 budget, thereby raising national emissions above the CAMR cap.

(4) *The proposed Pennsylvania Rule cites concerns about local deposition, but does not specifically regulate the species of mercury that deposits locally.* Mercury is emitted from EGUs as several distinct species, notably oxidized mercury and elemental mercury. However, oxidized mercury is the only species that contributes to local deposition in Pennsylvania (see ENVIRON 2006). Emissions of oxidized mercury can be reduced to low levels at a reasonable cost (see URS 2006). Thus, most of the high costs illustrated in Figure ES-1 represent costs to reduce elemental mercury; these costs would not yield any substantial reductions in Pennsylvania deposition. Moreover, national emissions would be essentially identical regardless of whether the proposed Pennsylvania Rule was enacted or Pennsylvania units were simply regulated by CAMR. Thus, the large costs imposed on

affected units by the Pennsylvania Rule would yield essentially no additional environmental benefits.

C. Case Study of Emissions and Costs of the Pennsylvania Rule Compared to the Alternative Approach

In this report, we analyze a regulatory alternative ("Alternative Approach") that would address concerns about local deposition in Pennsylvania by specifically regulating emissions of *oxidized* mercury. We have developed estimates of the costs of the Alternative Approach and the Pennsylvania Rule for a single large PPL electricity generating unit (Brunner Island Power Plant) to illustrate what is at stake in terms of overall Pennsylvania mercury emissions and compliance costs for Pennsylvania facilities by selecting the Pennsylvania Rule rather than the Alternative Approach.

1. Alternative Approach

The Alternative Approach would allow Pennsylvania units to participate in CAMR trading, but would regulate emissions of oxidized mercury on a unit-by-unit basis. Modeling by ENVIRON indicates that this Alternative Approach would result in no appreciable difference in Pennsylvania deposition compared to the Pennsylvania Rule in its current form (see ENVIRON 2006). In our empirical analysis, we assume that the Alternative Approach would require a 90 percent reduction in oxidized mercury from uncontrolled levels at Brunner Island.

2. Results of Empirical Analysis for Brunner Island Power Plant

The empirical results for the Brunner Island plant are based on estimates of control costs and effectiveness developed by URS, allowance price projections by the U.S. Environmental Protection Agency (EPA), and assumptions regarding the allocation of initial allowances based upon calculations performed by URS. Note that although this empirical analysis applies specifically to Phase 2 of both regulatory scenarios (2015 and thereafter), the Phase 1 CAMR budget for Pennsylvania is sufficiently small that a similar analysis would also apply to a Phase 1 comparison of the regulatory options (see URS 2006 for Phase 1 allocations).

a. Pennsylvania Mercury Emissions

Based on allowance price projections by the EPA and information on the cost of controls at Brunner Island from URS (see URS 2006), Brunner Island is expected to make substantial reductions in total mercury emissions under the Alternative Approach. Although Brunner Island is expected to be a net buyer of allowances, our results suggest that it will reduce emissions of total mercury by approximately 90 percent from mercury content of inlet coal, and of oxidized mercury by 90 percent relative to uncontrolled levels, under the Alternative Approach.

Figure ES-2 summarizes total annual mercury emissions from Brunner Island under uncontrolled conditions, under CAIR, and under the two regulatory cases considered. The figure illustrates that the Pennsylvania Rule would provide very small additional reductions in mercury emissions at Brunner Island, relative to those expected to be achieved under the Alternative Approach.

Moreover, emissions of oxidized mercury would not differ substantially between the two scenarios (see URS 2006).

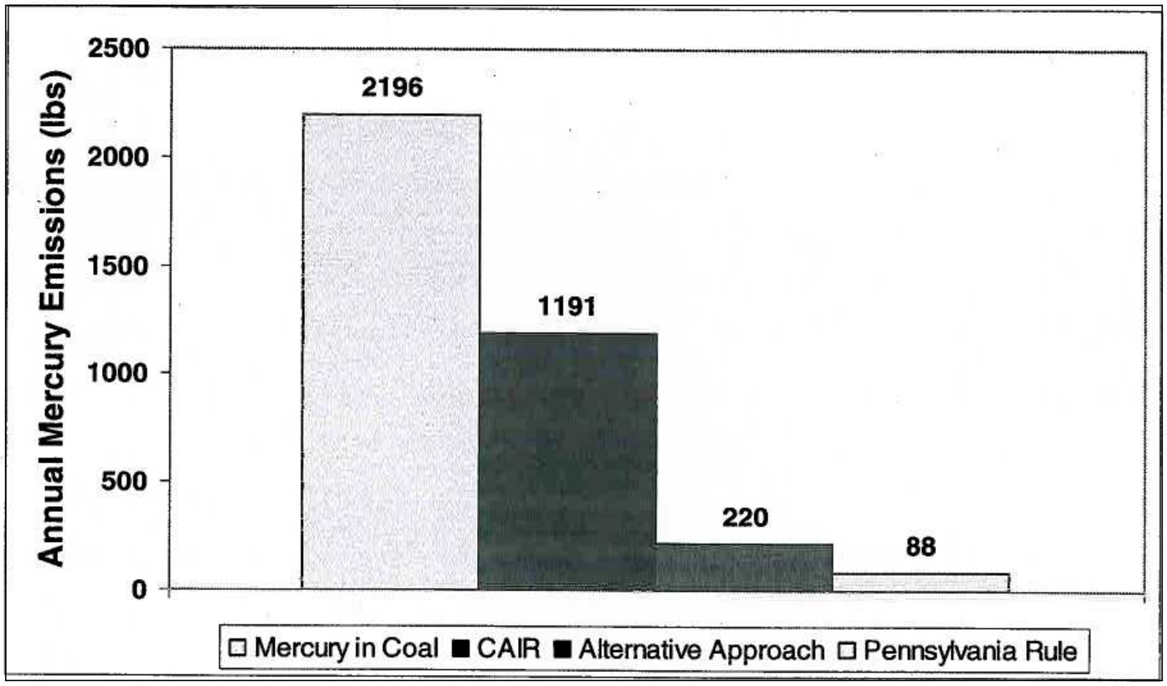

Figure ES-2. Mercury Emissions at Brunner Island in the Baseline and in the Two Scenarios Analyzed

Under the proposed Pennsylvania Rule, which from 2015 onward would require compliance with the CAMR Phase 2 allocation on a unit-by-unit basis with no trading allowed, emissions of total mercury at Brunner Island would be required to be reduced by about 96 percent or more from mercury in coal. Under the Alternative Approach, emissions of total mercury from Brunner Island are projected to be reduced by about 90 percent from mercury content of coal, and emissions of oxidized mercury reduced by 90 percent from uncontrolled levels. (The mercury emissions under the Alternative Approach represent the reductions that would be cost-effective for Brunner Island to make given its marginal cost curve and the projected allowance prices.) Thus, the proposed Pennsylvania Rule would reduce total mercury emissions from Brunner Island by at most only about 6 percentage points more from the total inlet mercury than the Alternative Approach – assuming that the level of reduction called for in the Pennsylvania Rule is technologically and economically feasible. (Note that because of the national cap, there would be *no* difference in *national* mercury emissions between the Pennsylvania Rule and the Alternative Approach.)

b. Pennsylvania Compliance Costs

Cost savings to Brunner Island from being able to participate in interstate trading would be high, because interstate trading avoids the need for Brunner Island to install very expensive controls to achieve the last few pounds of emissions reductions (above and beyond reductions achieved by more cost-effective technology). Indeed, these last pounds require technology at the margin that is estimated to cost more than $100,000 per pound, in contrast to a projected allowance price of less than $50,000 per pound. (See URS 2006 for information on the costs of mercury emission control technologies.)

The average annual costs of achieving total mercury emissions reductions under the two scenarios are illustrated in Figure ES-3. The costs shown in Figure ES-3 reflect both the compliance costs to reduce mercury emissions at Brunner Island and the costs of allowance purchases by Brunner Island (in the case of the Alternative Approach). (The allocation of mercury allowances to the Brunner Island units under the Alternative Approach is assumed to be the same as that provided under the Pennsylvania Rule). Figure ES-3 indicates that the average cost per pound for the additional 6 percentage points of abatement under the Pennsylvania Rule would be high. The rectangle to the right in Figure ES-3 shows the large additional costs that would be incurred to achieve these small additional mercury emissions reductions at Brunner Island.

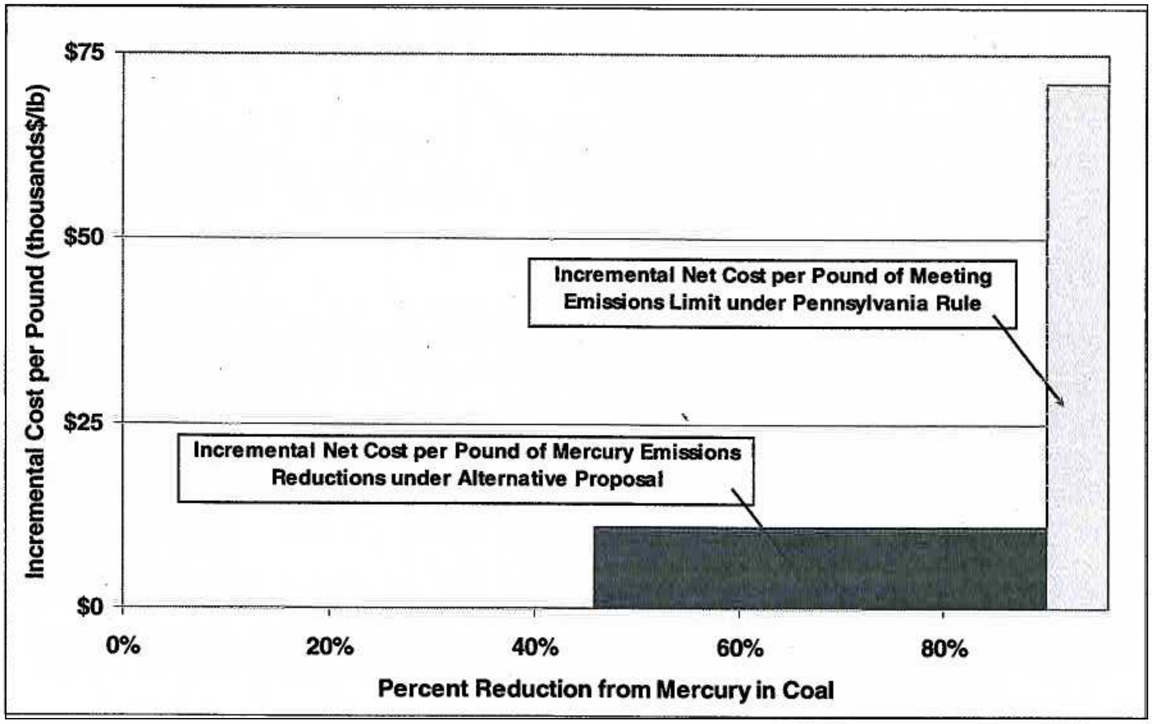

Figure ES-3. Average Net Cost per Pound of Mercury Emissions Reductions at Brunner Island under Alternative Approach and Average Net Cost per Pound for Additional Reductions under Pennsylvania Rule.

D. Conclusions

These empirical results support two major conclusions regarding what is at stake for Pennsylvania if it were to adopt the Pennsylvania Rule rather than the Alternative Approach.

(1) Any environmental benefits for the Pennsylvania Rule as compared to the Alternative Approach would be small at best and could be negative. As documented in the ENVIRON report, there would be essentially *no* difference in mercury deposition in Pennsylvania under the two alternatives. Reductions in *total* Pennsylvania mercury emissions expected under the Pennsylvania Rule would be similar to the reductions expected under the Alternative Approach, assuming technology to achieve the stringent Pennsylvania Rule target were feasible; if the technology to meet the Pennsylvania Rule was infeasible for some sources, national total mercury emissions could *increase* under the Pennsylvania Rule (because of the possibility of an alternative emission standard).

(2) The additional cost of compliance with the Pennsylvania Rule as compared to the Alternative Approach would be very high.

I. Introduction and Background

Emissions trading has emerged over the last decade as a major tool for controlling air pollution in the United States. Virtually all of the major programs and proposals to improve air quality now involve some form of emissions trading. The concept of emissions trading is attractive both because it provides a mechanism to lower the overall cost of meeting air quality objectives and because it provides greater certainty that air quality objectives are met than the traditional "command-and-control" approach. Under a command-and-control approach, uniform emissions standards are set for all facilities. Facilities at which it is infeasible to meet the standard generally receive exemptions, resulting in greater air pollution. Moreover, because emissions standards typically are set in terms of emissions per unit of input or output (e.g., pounds per kilowatt-hour of electricity produced), the overall level of emissions fluctuates with changes in input or output. Under a cap-and-trade program, facilities that cannot achieve the standard or that increase their generation must purchase reductions from other facilities so that the overall level of emissions remains the same. Extensive experience with emissions trading programs over the last decade provides strong evidence that these potential economic and environmental gains are achieved in practice.

This Report provides an assessment of emissions trading and its application to regulation of mercury emissions from coal-fired Electricity Generating Units (EGUs) in the United States, a program that was promulgated by the U.S. Environmental Protection Agency (EPA) in March 2005. Because Pennsylvania is considering adopting regulations that would not allow mercury trading for Pennsylvania facilities, we consider the potential advantages of an alternative approach that would allow EGUs to trade mercury allowances on the national market, and would specifically regulate emissions of *oxidized* mercury, the species that deposits locally, on a facility-by-facility basis (referred to as the "Alternative Approach").

The Report is organized as follows. The remainder of this section provides an overview of the concept of emissions trading, including a simple example of gains from trading, as well as a summary of the major features of an emissions trading program. Section II summarizes several large trading programs that have been developed in the United States over the past decade. Section III provides an overview of the major economic and environmental gains that these programs have achieved. Section IV provides information on the potential national gains of a cap-and-trade program for mercury relative to a command-and-control approach, and discusses how EPA determined state mercury budgets for CAMR. Section V provides an analysis of the advantages for Pennsylvania in adopting the Alternative Approach rather than the proposed Pennsylvania Rule.

A. Concept of Emissions Trading

The concept of emissions trading is simple. Under a cap-and-trade program,[1] an aggregate cap on emissions is set that defines the total number of emissions "allowances," each of which provides

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[1] There are two other types of emissions trading programs besides cap-and-trade programs. The other types are usually termed reduction credit programs and averaging programs. We focus on the cap-and-trade program because it is the type that is relevant for controlling mercury emissions from power plants. See Ellerman et al. (2003) for overviews of these other types of trading programs.

its holder with the right to emit a unit (typically a ton[2]) of a particular compound. The permits are initially allocated in one of several ways, typically directly to existing sources. Each source covered by the program must hold permits to cover its emissions, with sources free to buy or sell allowances amongst themselves.

By giving regulated facilities the flexibility to trade emissions allowances, the compliance costs of achieving an emissions target can be reduced. The cap set on the overall level of emissions provides certainty that the emission target will be achieved. Although emissions trading would not be appropriate for all situations, it is ideally suited for pollutants such as elemental mercury for which effects are due to cumulative emissions over a long period of time and a broad geographic region (ENVIRON, 2006).

B. A Simple Example to Illustrate the Cost-Effectiveness of Emissions Trading

A simple numerical example illustrates how emissions trading can reduce control costs relative to a traditional approach that is based upon setting uniform emissions standards (i.e., traditional command-and-control). Figure 1 illustrates a typical situation that could face facilities complying with a single uniform emission standard. Typically, the cost per ton of reduction rises as the level of reduction required is increased, and, usually due to differences in plant design and engineering, this marginal cost could be substantially higher for one plant compared to another. For example, in reducing emissions to meet the standard, Plant I is assumed to incur a cost of $1,500 for the *last* ton of emissions reduced, while Plant II spends $3,000 for the *last* ton it reduces. (In Section I.A below we show the overall gains taking into account all potential emission reductions, not just the last ton.) These two facilities might be different plants within the same company, plants owned by different companies in the same sector, or plants in completely different sectors. The particular emissions standards that are considered here in comparison to the trading approach might be based upon a common regulatory standard or on completely separate regulations.

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[2] As noted below, the allowance unit in a mercury emissions trading program would be much smaller—one ounce under the EPA Clean Air Mercury Rule (CAMR).

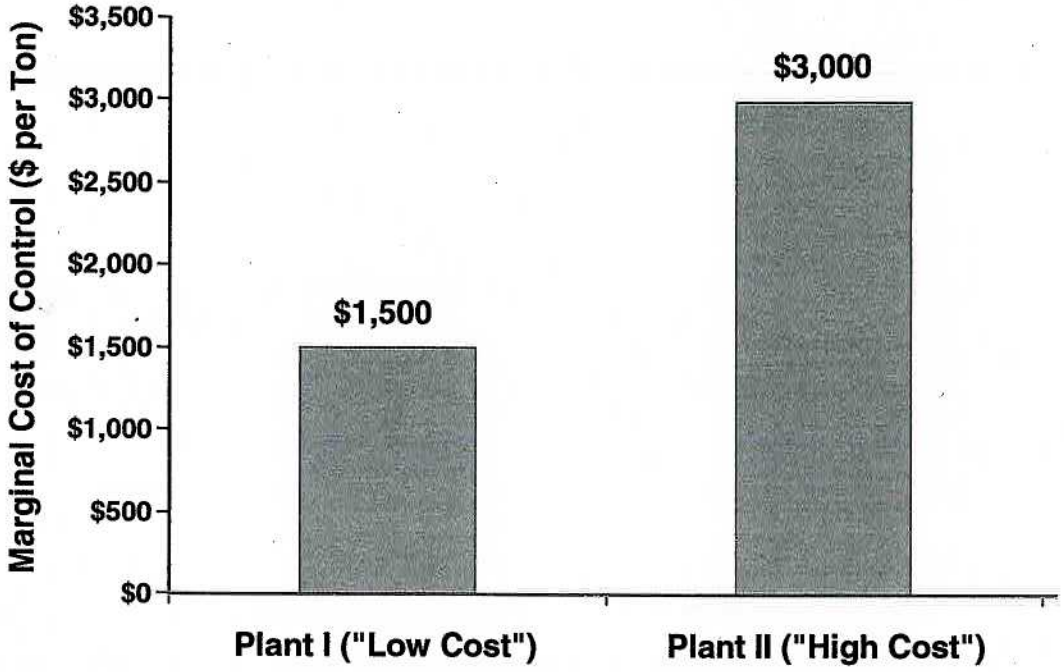

Figure 1. Marginal Costs of Meeting Hypothetical Standard at Two Plants

Clearly, the same overall reduction in emissions could be achieved at lower compliance costs by tightening controls at Plant I by one ton and relaxing them at Plant II by one ton. Initially, loosening controls at Plant II by one ton saves $3,000, whereas tightening controls by one ton at Plant I would raise costs by only $1,500, for a net savings in compliance costs of $1,500 to reduce that ton. Under a cap-and-trade program, these net savings would be shared by the two plants, and the same level of total emission reductions would be achieved.

Under a cap-and-trade program, each source would compare its own emissions control costs with the market price and determine whether it is profitable to control more and sell allowances to others, or to control less and buy allowances to cover the additional emissions. The trading mechanism allocates emissions reductions among sources in the most cost effective manner, relying on individual information and self-interest—rather than administrative regulation—to determine compliance decisions by each individual source.

Suppose in this simple numerical example that the market price of an emissions credit or allowance were $2,000 per ton, and that the two facilities were initially allocated allowances consistent with the individual emissions levels required under the emissions standard. Figure 2 shows how each of the sources would gain from the market with regard to the last ton controlled. Plant I (low-cost seller) gains by further reducing its emissions by one more ton than the standard requires and selling the allowance it no longer needs to Plant II; it receives $2,000 for the allowance but pays only $1,500 to achieve the reduction, for a net gain of $500. On the other side of the transaction, Plant II (high-cost buyer) is able to buy the allowance for $2,000 and reduce its compliance costs by $3,000, for a net savings of $1,000. Thus, the total savings in compliance costs of $1,500 for that ton is split between the buyer and the seller, with both gaining from trading.

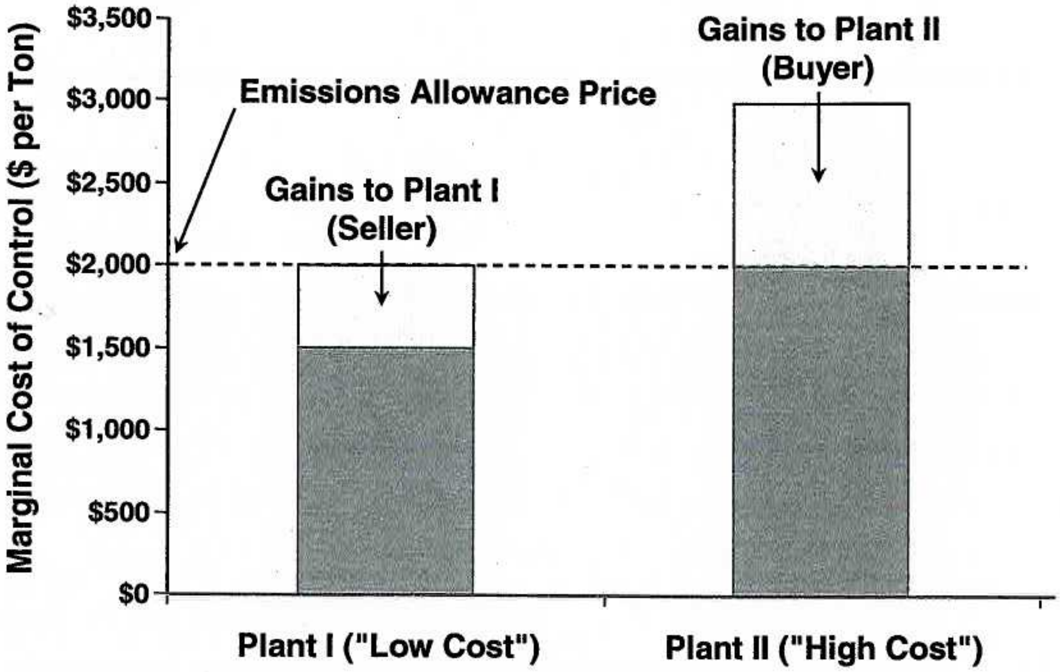

Figure 2. Gains to Plants from the Trade of a Single Emissions Allowance

This simple example illustrates both how emissions trading operates—through exchanges between buyers and sellers of the right to emit a ton—and the substantial cost-savings achieved. Although many details must be specified, the basic concept is illustrated in these two figures.

C. Other Features of Emissions Trading Programs

Although the concept is simple, various features must be specified in an emissions trading program in order to ensure that economic and environmental objectives are achieved in practice. The following is a list (derived from Harrison 1999) that divides the major features of emissions trading programs into two major categories: design issues and implementation issues.

- *Design Issues*. These include the decisions that arise as the program is designed and turned into a specific regulatory program.
    - *Allocation of initial allowances*. Some method is required to distribute the initial allowances under the cap-and-trade approach. Basic methods include various formulas to distribute initial allowances to participants on the basis of historical information ("grandfathering") or on the basis of updated information ("updating") as well as auctioning of the initial allowances.[3]
    - *Geographic or temporal flexibility or restrictions*. Emissions trading can allow for the possibility of restricting trading among different geographic regions covered by the program if there is evidence that emissions have substantially different effects when

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[3] Further details on allocation of initial allowances may be found in Harrison and Radov (2002).

emitted in different locations. The trading program can also allow for the option to bank (i.e., reduce emissions more than required in a given year and "bank" the surplus for future internal use or sale) or borrow (i.e., reduce less than required in a given year and "borrow" against future reductions, with the borrowed amount made up by reducing more than required in subsequent years).

  - *Emissions sources that are required or allowed to participate*. This includes specification of the universe of sources that must participate in the trading program. It also includes the possibility of allowing additional sources to opt-in to the program.

  - *Institutions established to facilitate trading*. This includes the possibility of encouraging third parties (e.g., brokers) to participate in trading, as well as the possibility of setting up an ongoing auction or other institutions to increase liquidity and establish market prices.

- *Implementation Issues*. A number of decisions must be made as the program is implemented.

  - *Monitoring and reporting of emissions*. Methods must be designed to monitor and report emissions from each participating source.

  - *Determining compliance and enforcing the trading program*. A means of determining whether sources are in compliance and of enforcing the program if sources are out of compliance must be developed for the program to work effectively.

  - *Maintaining and encouraging participation*. This relates to decisions made regarding how to keep sources in the program and encourage participation of sources whose participation is optional (e.g., those given the opportunity to opt-in).

As discussed in the next section, the existing emissions trading programs have addressed these various design and implementation issues to produce environmentally beneficial and cost-effective programs.

II. Emissions Trading in the United States

As noted in Section I, emissions trading has been used extensively over the past decade to regulate air emissions in the United States. Table 1 summarizes the five major cap-and-trade programs that have been established in the United States, including the recent programs promulgated by the EPA in 2005. The U.S. EPA has administered all of the programs discussed here except for the Regional Clean Air Incentives Market (RECLAIM), the Los Angeles air basin program that is administered by the South Coast Air Quality Management District. These programs are summarized briefly below.

Table 1. Summary of Major Cap-and-Trade Emissions Trading Programs

Program	Agency	Type	Emission	Source	Scope	Year
RECLAIM	South Coast Air Quality Management District	Cap-and-Trade	NO_x; SO_2	Stationary	Los Angeles Basin	1994-Present
Acid Rain Trading Program	U.S. EPA	Cap-and-trade; Reduction Credit	SO_2	Electricity Generation	U.S.	1995-Present
Northeast NO_X Budget Trading	U.S. EPA; 12 states and D.C.	Cap-and-Trade	NO_x	Stationary	Northeast U.S.	1999-Present
Clean Air Interstate Rule (CAIR)	U.S. EPA	Cap-and-Trade	NO_x, SO_2	Stationary	Eastern U.S.	To begin in 2009 (NO_x) and 2010 (SO_2)
Clean Air Mercury Rule (CAMR)	U.S. EPA	Cap-and-Trade	Mercury	Stationary	U.S.	To begin in 2010

A. Acid Rain Trading Program

The largest and best-known cap-and-trade program in the United States is the program for sulfur dioxide (SO_2) created by Title IV of the 1990 Clean Air Act Amendments. This program is often referred to as the Acid Rain Trading Program because the major motivation for the program was to prevent acid rain damage in the United States. Because of its large scale and high profile, the success of the Acid Rain Trading Program has contributed more than anything else to the change in attitude towards emissions trading in the 1990s, and it is often cited as an example for other applications.

The Acid Rain Trading Program created a national cap of roughly nine million tons of SO_2 emissions per year from electricity generating plants. The national target was to be achieved in two phases. During Phase 1, lasting from 1995 through 1999, the 263 electricity generating units emitting the largest volume of SO_2 were subject to an interim cap that required projected average emissions from these units to be no greater than approximately 2.5 lbs of SO_2 per million Btu of heat input. In Phase 2, beginning in 2000 and continuing indefinitely, the program was expanded to include virtually all fossil-fueled electricity generating facilities and to limit emissions from these facilities to a cap of approximately nine million tons—which implies an average emission rate of less than 1.2 lbs of SO_2 per million Btu. The final Phase 2 cap will eventually reduce total SO_2 emission from electricity generating units to about half of what they were in the early 1980s.

This cap on national SO_2 emissions was implemented by issuing tradable allowances, each representing the right to emit one ton of SO_2, equal to the total annual allowed emissions, and by requiring that the owners of all fossil-fuel-fired electricity generating units surrender an allowance for every ton of SO_2 emissions. Allowances not used in the year for which they are allocated can be banked for future use or sale. These allowances are allocated to owners of affected units free of charge, generally in proportion to each unit's average annual heat input during the three-year baseline period, 1985-1987. A small percentage (2.8 percent) of the allowances allocated to affected units are withheld for distribution through an annual auction conducted by the EPA to encourage trading and to ensure the availability of allowances for new generating units. The revenues from this auction are returned on a *pro rata* basis to the owners of the existing units from whose allocations the allowances are withheld.

B. RECLAIM

While the Acid Rain Trading Program was being developed in the early 1990s, regulators in the Los Angeles air basin were simultaneously developing another prominent cap-and-trade program. This program, called the Regional Clean Air Incentives Market (RECLAIM), was significant both in some of its provisions and as the first major example of a tradable permit program developed by a local jurisdiction rather than a federal authority.

The South Coast Air Quality Management District (SCAQMD) approved the RECLAIM program in October 1993 after a three-year development process, and the program began operation in January 1994. RECLAIM was developed as an alternative means of achieving the emission reductions of nitrogen oxides (NO_x) and SO_2 mandated by a set of command-and-control measures in the 1991 Air Quality Management Plan to bring the Los Angeles Basin into compliance with National Ambient Air Quality Standards. Under RECLAIM, the caps for both NO_x and SO_2 were set higher than expected emissions in the initial years, but the overall caps were reduced steadily over time so that, by 2003, emissions from sources emitting more than four tons of either pollutant would be reduced to about 50 percent below early-1990s emission levels. From 2003 on, the caps have remained constant.

Several features of the design of the RECLAIM program distinguish it from the Acid Rain Trading Program. First, a heterogeneous group of participants is covered by the program, including power plants, refineries, cement factories, and other industrial sources. Second, the RECLAIM program distinguishes between emissions in two geographic zones. Since emissions in the Los Angeles Basin generally drift inland from the coast, sources located in the inland zone were allowed to use RECLAIM Trading Credits (RTCs) issued for facilities in either the inland or coastal zones, but sources located in the coastal zone could use only RTCs issued for facilities in the coastal zone. A third distinctive feature of the RECLAIM program is that it does not allow banking. RECLAIM does provide limited temporal flexibility, however, by grouping sources into two twelve-month reporting periods, one from January through December and the other from July through June, and by allowing trading between sources in overlapping periods.

C. Northeast NO_x Budget Trading Program

The Northeast NO_x Budget Trading program grew out of provisions in the Clean Air Act Amendments of 1990 that facilitated common actions by the District of Columbia and twelve states in the Northeastern United States[4] to deal with concerns about regional tropospheric ozone, or "smog." The states adopted a cap-and-trade program to reduce NO_x emissions from electricity generating facilities having 15 MW of capacity or greater, and equivalently sized industrial boilers, by about 60 percent from uncontrolled levels in a first phase (starting in 1999) and by up to 75 percent in a second phase (starting in 2003).[5]

A unique feature of the program is that it operates only during the summer months, from May through September, when NO_x effects on ozone concentrations are greatest in this part of the country. Although the environmental objective is to reduce the incidence of ozone non-attainment, the program does not contain provisions that would distinguish days during the summer when the ozone standard is exceeded from days when it is not. Several ideas to address this problem were considered, but none were deemed feasible (Farrell 2000). Instead, the program relies on the decrease in the overall level of NO_x emissions during the critical summer season to achieve its goal.

D. Clean Air Interstate Rule

The Clean Air Interstate Rule (CAIR), promulgated by the EPA on March 10, 2005, sets new standards for SO_2 and NO_x emissions from new and existing fossil fuel-fired electricity generation units in 28 Eastern states and Washington, DC.[6] CAIR establishes two phases of caps for these air emissions, with the second cap lower than the first. Phase 1 of the NO_x program takes effect in 2009, and Phase 1 of the SO_2 program takes effect in 2010. Phase 2 for both NO_x and SO_2 begins in 2015.

When CAIR is fully implemented, annual SO_2 emissions in covered states are expected be reduced by over 70 percent relative to 2003 levels, and annual NO_x emissions are expected to be reduced by over 60 percent. Each state covered by the regulation has an emissions reduction requirement. CAIR gives states the option of meeting their emissions reduction requirements by participating in a cap-and-trade program based on the successful Acid Rain Trading Program for SO_2 and the Northeast Budget Trading Program for NO_x. If states elect not to join the program, their emission reduction requirements are firm caps. The EPA considers participation in the cap-and-trade program to be the most cost-effective way for states to achieve their mandated emission reductions (70 *Federal Register* 25228).

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[4] The twelve are the six New England states (Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut) and the six Mid-Atlantic States (New York, New Jersey, Pennsylvania, Maryland, Delaware, and Virginia).

[5] Technically, these phases are the second and third of a three-phase program, the first phase of which consisted of re-labeling existing technology-based requirements and did not involve emissions trading.

[6] Although CAIR strengthens the cap on emissions from power plants only in Eastern states, the higher allowance prices give power plants across the country an incentive to reduce air emissions beyond levels of reduction without CAIR.

E. Clean Air Mercury Rule

On March 15, 2005, EPA promulgated the Clean Air Mercury Rule (CAMR), which sets standards for mercury (Hg) emissions from new and existing coal-fired generating units. Under CAMR, Hg emissions are capped at specific, nationwide levels to be achieved in two phases. The first phase will become effective in 2010 and establishes a cap of 38 tons per year; the second phase, effective in 2018, caps Hg emissions at 15 tons per year.

EPA expects that the 2010 target for mercury emissions will be achieved largely through the implementation of emissions control measures for CAIR. The increased use of flue gas desulphurization (FGD) to reduce SO_2 emissions and selective catalytic reduction (SCR) to reduce NO_x emissions will also reduce Hg emissions. Thus, Hg emissions reductions will be a "co-benefit" of SO_2 and NO_x emissions reductions in the early years.

As with CAIR, CAMR provides for a national cap-and-trade program that states may join to meet their Hg emissions budgets. If they choose not to participate in the program, their emissions budgets are firm caps.

III. Economic and Environmental Gains from Emissions Trading

This section provides information on the economic and environmental gains from emissions trading, drawing on experience from the three existing programs described above.

A. Economic Gains from Emissions Trading

As noted above, the economic rationale for emissions trading is straightforward. By giving businesses the flexibility to reallocate (trade) emissions credits or allowances among themselves, trading can reduce the compliance costs of achieving an emissions target.

1. Overview of Potential Gains to Buyers and Sellers

Figure 2 above reflects gains from the first allowance traded. There presumably will be more gains from additional trades. How far will such trading proceed? As Plant I sells more allowances to Plant II, the marginal cost of control at Plant I is likely to rise (as the level of emissions is reduced), while it falls at Plant II (as the amount of required reductions becomes less). Plant I stops selling at the point at which additional reductions cost more than $2,000 per ton, and Plant II stops buying when its marginal cost falls below $2,000 per ton. At that point, the total cost of achieving the overall reduction is minimized, and the marginal abatement costs at both plants are equal to the allowance price.

To illustrate how the market sets the price and how the overall gains from trade are achieved, we can think of each facility's marginal cost of controlling emissions as its demand curve for emission allowances. The maximum amount that a facility is willing to pay for another

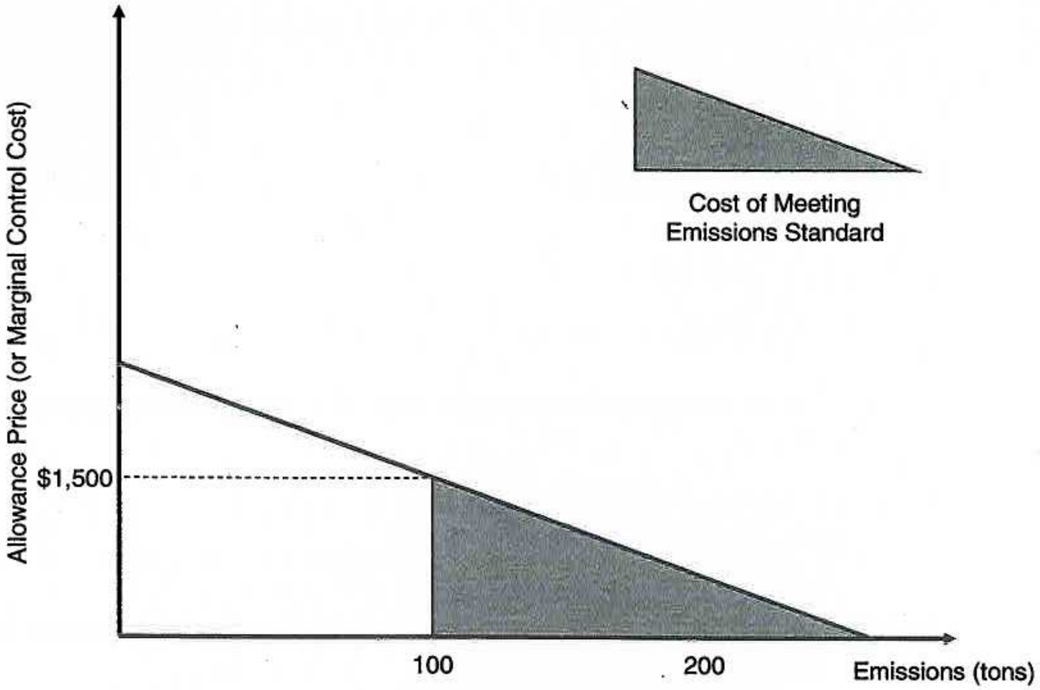

Figure 3. Cost to Plant I ("Low Cost") of Meeting Emissions Standard

allowance (allowance demand) is equal to what it would save from controlling one less ton (marginal control cost).

Figure 3 plots a hypothetical emissions allowance demand curve for Plant I, which has relatively low costs of emissions abatement and thus is a seller in the allowance market. The horizontal axis represents the number of tons emitted; moving to the right along the axis corresponds to higher emissions and lower control levels. Because marginal costs tend to increase as controls become more stringent, the price of allowances—which represents the marginal costs of reducing emissions—increases as more emissions are controlled. The marginal control cost for Plant I to achieve total emissions of 100 tons is $1,500 per ton (the value shown in Figure 2 above).

Figure 4 plots a hypothetical emissions allowance demand curve for Plant II, which has relatively high costs of emissions abatement and thus is a buyer in the allowance market. For this plant, the marginal control cost to achieve total emissions of 100 tons is $3,000 per ton.

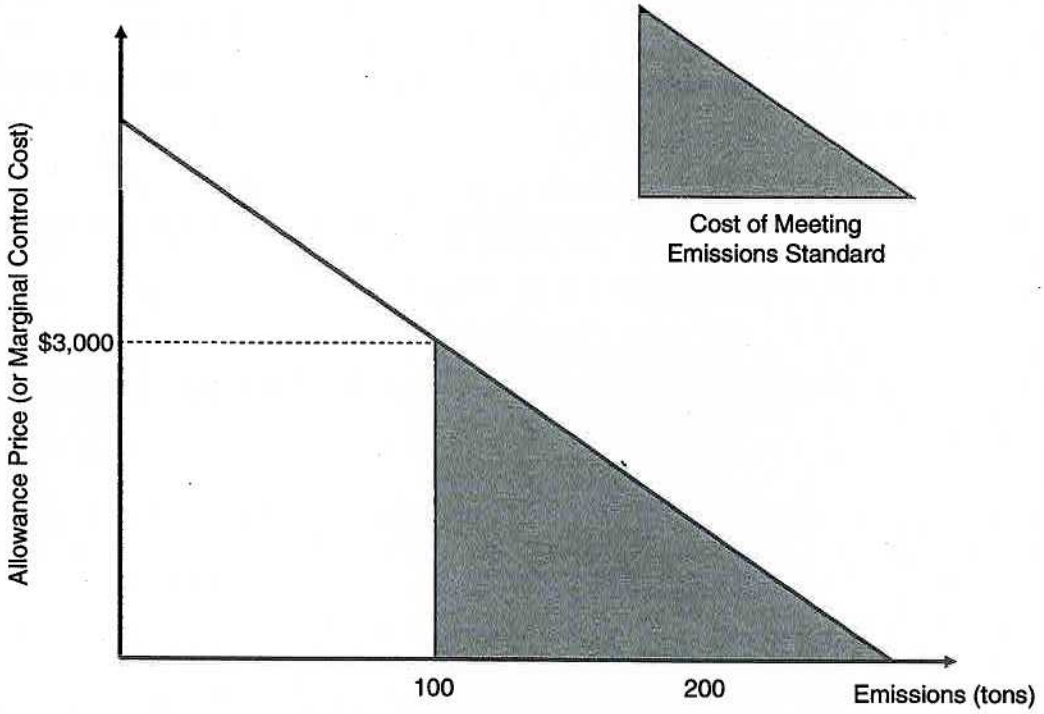

Figure 4. Cost to Plant II ("High Cost") of Meeting Emissions Standard

Both Plant I and Plant II gain from emissions trading, relative to a requirement that both achieve a given emission level. Figure 5 and Figure 6 show the savings from emissions trading for the two plants. As in the previous figures, the shaded regions represent the amounts spent on emissions control measures.

Plant I (the lower-cost facility) incurs additional control costs as it reduces its emissions from 100 tons to 50 tons; these extra costs are shown by the shaded trapezoid (b + c), the area of which is $87,500. That extra cost is more than offset, however, by revenues from the 50 allowances that it sells to Plant II at $2,000 each, as shown by the rectangle (b + c + d), the area of which is $100,000. Thus, the net gain to Plant I is the area of the triangle (d), which is $12,500.

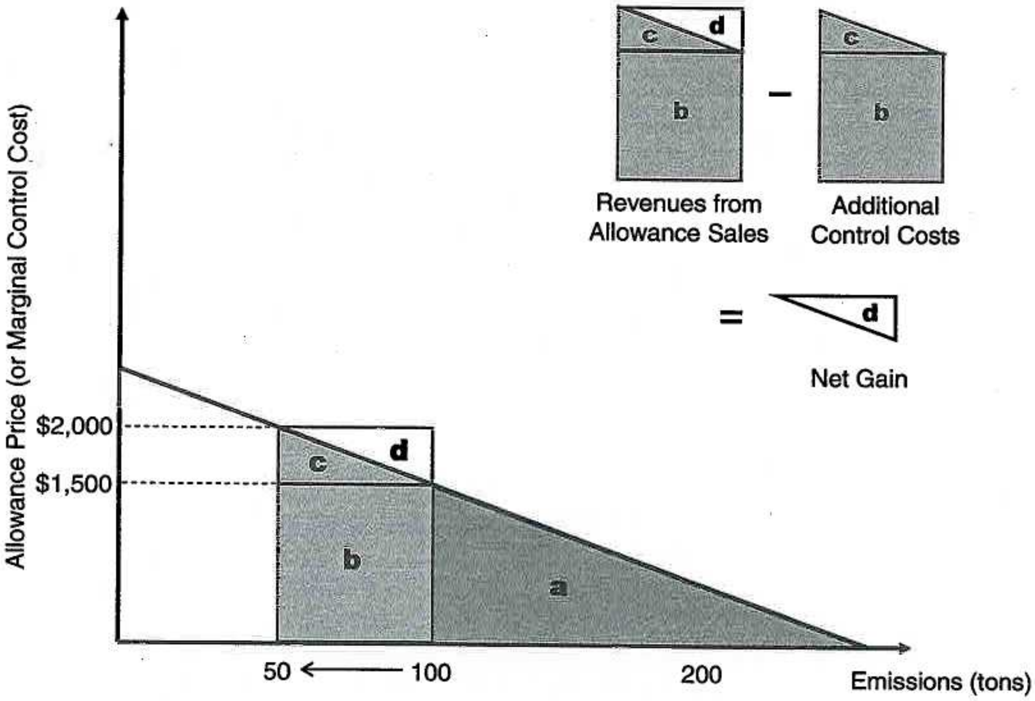

Figure 5. Cost Savings to Plant I ("Low Cost") through Emissions Trading

Figure 6 shows the results for Plant II, which increases its emissions from 100 tons to 150 tons. Plant II reduces its control costs by the area of the trapezoid (B + C), which has a value of $125,000. These savings are partly offset by the cost of purchasing 50 allowances from Plant I, which equals, at $2,000 each, $100,000 (the area of the rectangle B). Thus, the net savings to Plant II is $25,000.

The figures illustrate that both high-cost and low-cost participants gain from emissions trading relative to a program that would require them to achieve the same individual target. Under emissions trading, the combined savings for the two plants is $37,500 relative to the scenario without emissions trading. From the perspective of the environment, total emissions are unchanged relative to the emissions limit alternative. Since this example assumes no change in costs to the government relative to the emissions limit alternative,[7] the net overall gain is $37,500.

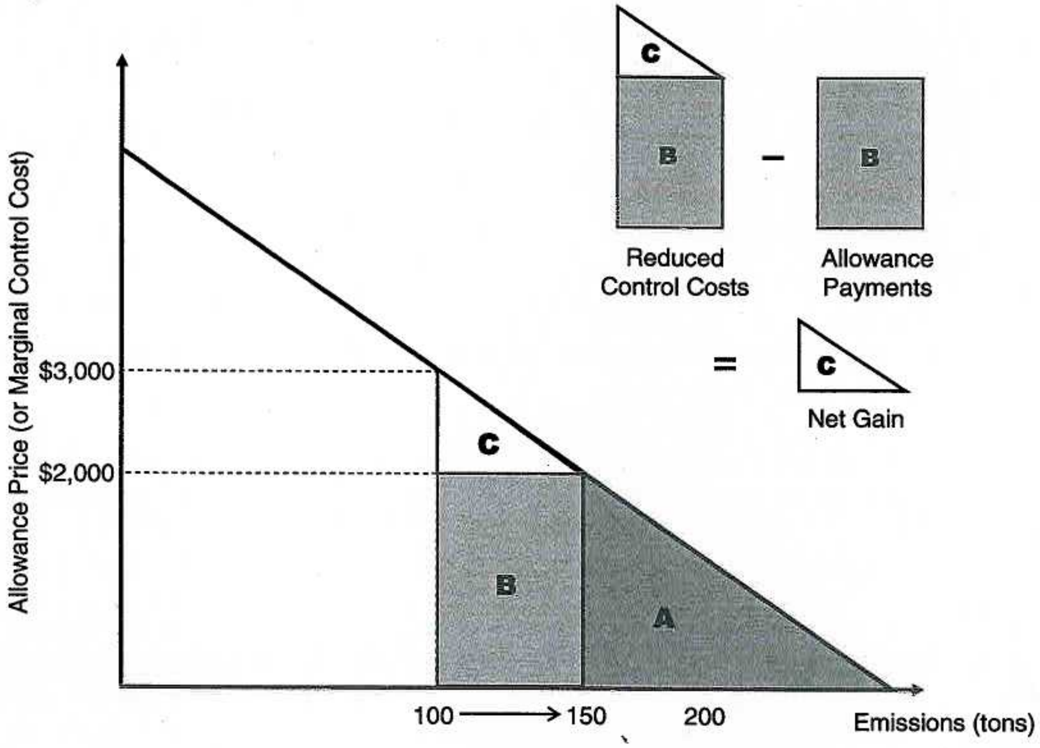

Figure 6. Cost Savings to Plant II ("High Cost") through Emissions Trading

2. Experience Shows Cost Savings Gains in Practice

Emissions trading has been successful in its major objective of lowering the cost of meeting emission reduction goals. The high volume of trading observed in nearly all programs provides circumstantial evidence that this objective has been achieved.

Several careful studies of the Acid Rain Trading Program that assessed the gains from trading, both across different facilities and over time through the banking provisions of the program, provide solid evidence of cost savings from emissions trading (Ellerman et al. 2000, Carlson et al. 2000). These gains are measured relative to estimates of the costs that would have been incurred to obtain the same emission reductions without emissions trading. The studies confirm

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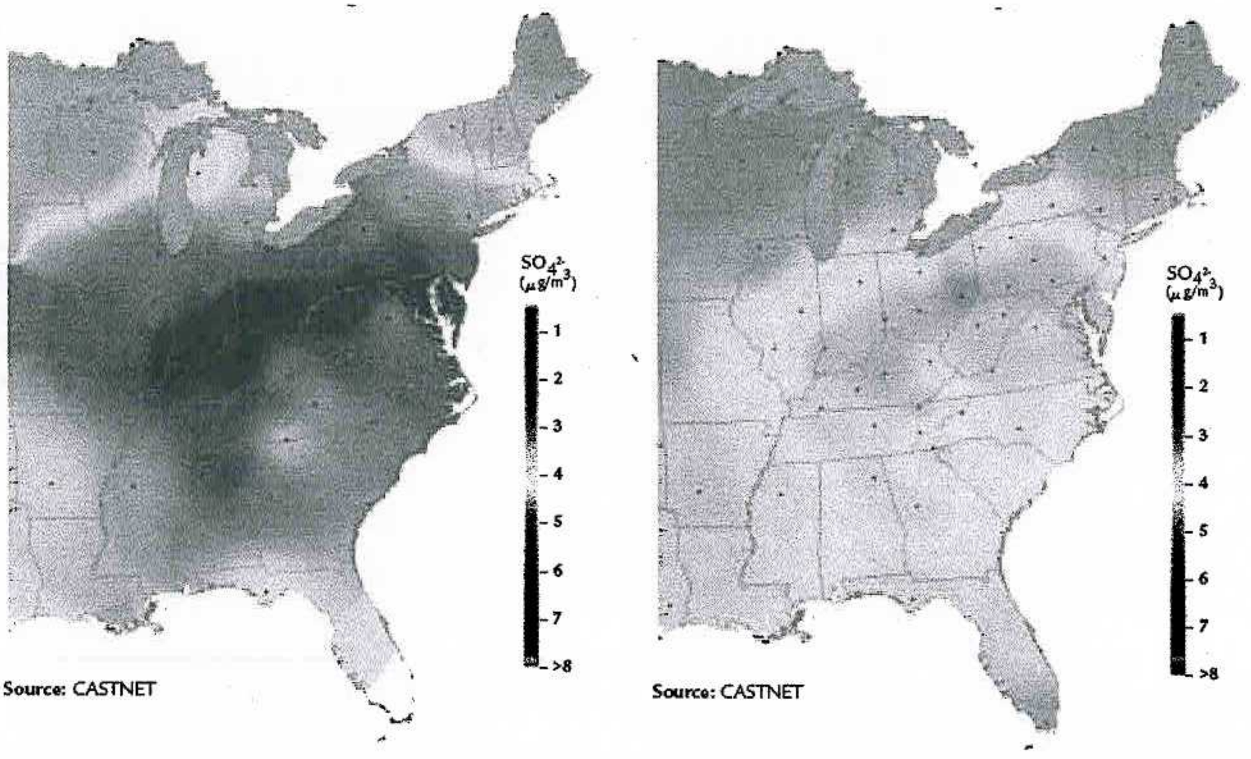
[7] In reality, command-and-control regulation relies upon substantial government review and oversight that carries significant costs. Such costs to the government would also typically be reduced under a cap-and-trade program.

that cost savings can be achieved. The overall cost savings are estimated to be about 50 percent relative to the costs of a command-and-control alternative.

RECLAIM and the Northeast NO_x Budget Trading program have not been subject to as careful retrospective review, but both have experienced substantial trading activity, which suggests cost savings. In RECLAIM, for instance, the overall trading volume in any given year exceeds the total annual allocation (as a result of trading in future vintages). Studies done when the program was introduced estimated cost savings would be about 40 percent of the total cost under command-and-control (Harrison and Nichols 1992). The extensive trading suggests these cost savings were achieved.

B. Environmental Gains from Emissions Trading

The use of emissions trading has enhanced—not compromised—the achievement of environmental goals. Emissions trading is sometimes portrayed as a way of evading environmental requirements, but the experience to date has demonstrated the opposite. For example, under the Acid Rain Trading Program, ambient sulfate concentration in the Eastern United States has been markedly reduced, as shown in Figure 7 below.



Source: EPA (2005a)

Figure 7. Annual Mean Ambient Sulfate Concentration in 1989-1991 (left figure) and 2002-2004 (right figure)

Enhanced environmental performance can be attributed to the increased flexibility associated with emissions trading for five major reasons.

- Banking has created incentives for early reductions;
- Caps have avoided limitations on emission reductions from plants where the emission standard is infeasible;
- Caps have avoided emissions increases associated with increased generation;
- Cost savings have provided incentives for more ambitious targets; and
- Allowance prices have provided incentives for businesses to find more effective control technologies and to optimize reductions from those already installed.

The following subsections provide information on these gains.

1. Banking Has Created Incentives for Early Emission Reductions

Where emission reduction requirements are phased in and businesses can bank emission reductions—as was the case in most of the programs reviewed in Section II—the achievement of the required emission reduction has been accelerated. The early reductions may defer the achievement of future annual emissions control targets as the banked credits are used. However, as long as a positive discount rate is assigned to the benefits associated with emission reductions—as is surely the case, since benefits today are preferred to the same benefits tomorrow—accelerating the timing of the cumulative required emissions reductions represents a net environmental gain.

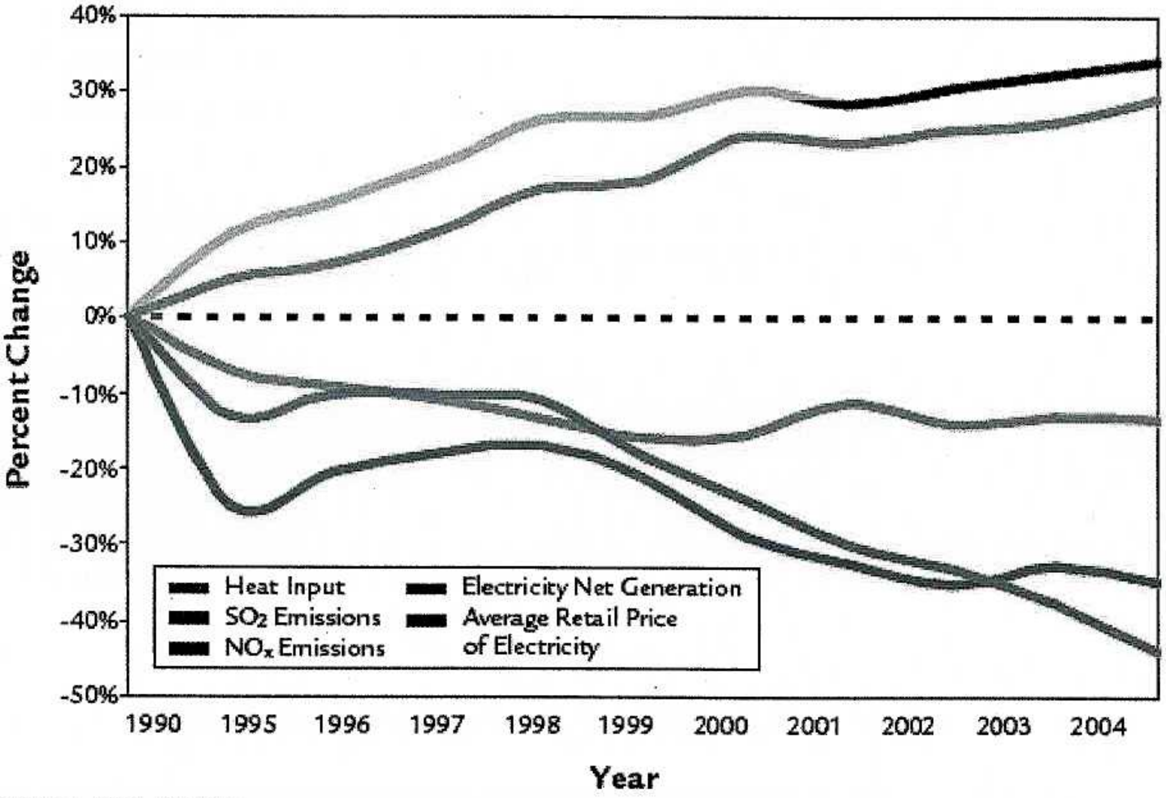
2. Caps Preserve Reductions Where Standards Are Infeasible at Particular Plants

Allowing businesses that face high marginal costs of abatement, or even technological infeasibility, to comply with environmental requirements by buying allowances, effectively paying others to reduce more on their behalf, has eliminated one of the features of command-and-control programs that diminishes environmental effectiveness. In a command-and-control program, economic hardship or technological barriers can be dealt with only by relaxing the emissions standard in some way, such as by allowing exemptions or setting the standard as a "lowest common denominator" that all covered entities can meet. While often justified, these exceptions reduce the regulation's environmental effectiveness because they are one-sided: standards are relaxed to avoid "hardships" for some facilities, but increased emissions cannot be offset by increasing standards at facilities for which abatement is less expensive or easier technologically. The net result is more emissions than would be produced by an "ideal" regulation (i.e., one taking into account differing compliance costs).

Emissions trading programs avoid this problem by requiring the facility that faces difficulty meeting the standard to obtain offsetting reductions from another facility. The result is a decentralized mechanism for offsetting emissions that does not detract from achieving the environmental goal.

3. Caps Avoid Emissions Increases Due to Increased Generation

Under the emissions limit approach to reducing air emissions, the maximum allowable emission rate typically depends on fuel input or electricity generation (i.e., the emissions limit is expressed as units of emissions—e.g., tons or pounds—per unit of fuel burned or unit of electricity produced). Thus, if fuel input or electricity generation increases, the level of allowable emissions increases as well, and total emissions would increase. Under a cap-and-trade program, on the other hand, the cap represents a level of emissions, not an emissions rate, so changes in total fuel input or electricity generation should not affect total emissions. If total generation increases, for example, total emissions would not increase under a cap-and-trade program.



Source: EPA (2005a)

Note Heat input and emissions data reflect Acid Rain Trading Program units. Generation reflects all fossil fuel-fired electricity-only plants in the United States. Retail price reflects full national values for the electricity-generating sector.

Figure 8. Trends in Electricity Generation and Emissions from Electric Power Sources

Since the passage of Title IV of the 1990 Clean Air Act Amendments, which established the Acid Rain Trading Program, fuel input and electricity generation have increased by approximately 30 percent, but SO_2 emissions have decreased by nearly 40 percent, demonstrating the greater effectiveness of cap-and-trade in avoiding emissions increases due to increased generation. These trends are illustrated in Figure 8.

4. Potential Cost Savings Have Provided Incentives to Agree on Environmental Targets

A fourth reason for enhanced environmental results under a trading program is the greater ability to gain consensus on the environmental goal, and even adopt a more demanding goal, when flexibility exists. An important reason for the acceptance of more demanding environmental targets in conjunction with trading appears to be that the allocation mechanism can be used to win over those who might otherwise stand to lose the most from tighter regulations. Also, the lower overall costs of achieving the target mean that more reductions are affordable (all other things being equal).

The inclusion of emissions trading in Title IV of the Clean Air Act Amendments of 1990 broke what had been a decade-long stalemate on acid rain legislation. In the Northeast NO_x trading program, state officials and regulators turned to emissions trading as a better means to achieve compliance with the National Ambient Air Quality Standards for ozone, a goal which had long eluded these states (and a number of others) despite ample regulatory authority in the existing Clean Air Act. Similarly, regulators in Southern California adopted emissions trading in both SO_2 and NO_x as a more likely means of achieving the emission reductions that were already required. There also is evidence that more stringent emission standards were set for various categories of mobile sources because of the flexibility provided by the Averaging, Banking, and Trading (ABT) programs, another form of emissions trading.

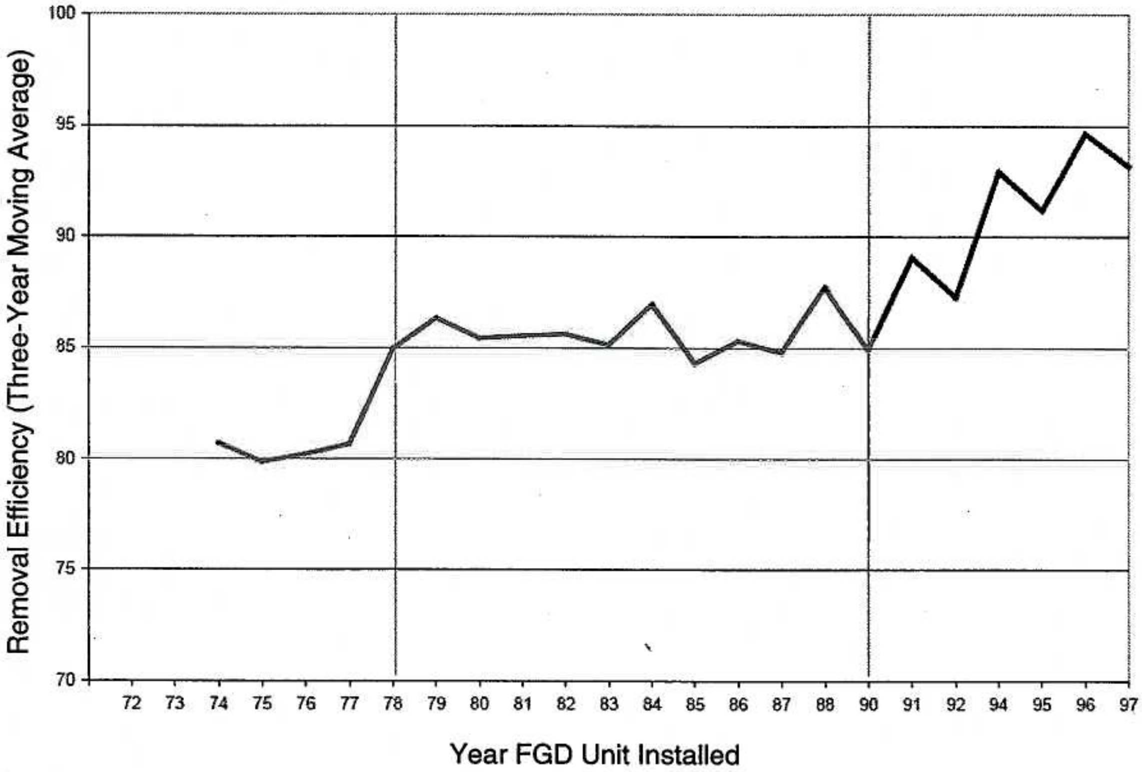
5. Trading Has Provided Incentives to Develop More Effective Control Technologies

Trading also can provide incentives to find more effective emissions control technologies. Trading programs create greater incentives for innovation in emissions-reduction technologies than command-and-control regulations. While the latter may "force" some technological development, there is no incentive to go beyond the standard, and indeed a disincentive because investments in developing more efficient abatement technology might be "rewarded" only by a tighter standard.

In contrast, the incentive to abate in cap-and-trade programs, where there is no specific standard for any single plant, is continuous across all levels of emissions, and any improvements in abatement technology will result in allowance savings (Swift 2001). There is also empirical evidence that the Lead-in-Gasoline Program, a trading program administered by the EPA from 1982 to 1987, led to more efficient adoption of lead-reducing technologies by refiners (Kerr and Newell 2001). Two additional studies provide solid evidence that Cap-and-Trade programs provide greater incentives for innovation than traditional command-and-control programs:

- Milliman and Prince (1989) examine incentives to develop technology to reduce emissions under five types of regulation: direct controls (i.e., command-and-control regulation), emission subsidies, emission taxes, free market permits, and auctioned marketable permits. They find that direct controls provide the lowest incentive for technological change.

- Popp (2001) investigates the development of SO_2 abatement technology before and after passage of the Clean Air Act Amendments of 1990, which established the Acid Rain Trading Program. Popp concludes that the switch from the earlier command-and-control policy to the market-based policy led to more environmentally effective SO_2 abatement technologies. As shown in Figure 9, SO_2 removal efficiency by FGD units was level during the 1980s but then rose markedly upon passage of the Clean Air Act Amendments of 1990.



Source: Popp (2001)
Note: The figure shows the average removal efficiency for newly installed flue gas desulphurization (FGD) units, presented as a three-year moving average. The vertical lines delimitate the three policy eras.

Figure 9. SO_2 Removal Efficiency Before and After Passage of the Clean Air Act Amendments of 1990

As confidence grows regarding the effectiveness of these incentives for innovation, it should be feasible to reduce emissions more using a cap-and-trade approach than would be likely under command-and-control regulation.

Another ancillary benefit is the significant improvement in the quality of environmental data that results from the monitoring requirements of emissions trading programs. Such careful monitoring is a necessary and worthwhile expense to achieve the cost savings and other benefits of emissions trading. Although emissions monitoring could be, and sometimes is, required of command-and-control regulation, more typically, emissions are not monitored since compliance is determined by inspection to ensure that the mandated equipment is installed and working or that the mandated practices are being followed. The superior information generated in a cap-and-trade program should contribute to better understanding of, and solutions to, remaining environmental problems.

IV. Projected Cost Savings and Mercury Budgets under the CAMR National Cap-and-Trade Program

This section provides information on the costs of a national cap-and-trade program to regulate mercury emissions from coal-fired power plants. As noted above, EPA does not provide specific information on the costs of a cap-and-trade program relative to the costs of a standard-based approach. However, a study was performed by the Energy Information Administration (EIA) during the rulemaking period. In this section, we also describe the methodology used by EPA to calculate state Hg emission budgets.

A. Projected Costs of National Cap-and-Trade Program for Mercury as Compared to Command-and-Control Approach

We first review information on the costs of the CAMR program compared to the costs of a national command-and-control regulation on mercury emissions.

1. Energy Information Administration Study

In January 2005, EIA evaluated alternative options for controlling mercury emissions. The EIA modeled EPA's CAMR cap-and-trade program, the alternative Maximum Available Control Technology (MACT) approach, and three additional scenarios to characterize technological uncertainties. The cap-and-trade program for mercury assumed in the EIA analysis differs somewhat from the form of CAMR announced in the Final Rule, in that EIA assumed a safety valve provision. The implications of this difference are discussed below.

2. EIA Results for Alternative Mercury Control Approaches

Table 2 below summarizes the EIA modeling results for the cap-and-trade program and MACT regulations.

Table 2. EIA Results for Alternative Mercury Control Approaches

	Present Value of Net Costs [(a)]	Hg Emission Reductions in 2025 from 2003 Baseline
Cap-and-Trade Program	$2 billion	19.8 tons
MACT	$8 billion	9.7 tons

Source: EIA (2005), p. 18

Note: (a) The present value of net costs represents discounted resource costs and safety valve payments. Costs cover 2005 though 2025 and are discounted at 7 percent.

Note that for the MACT regulatory alternative, costs are much higher than for the cap-and-trade alternative, while emission reductions in 2025 are substantially lower. As noted previously, this result occurs because the cap-and-trade strategy allows power plant operators to reduce mercury emissions at the plants where it is most economical, while under the MACT approach, some plants with high control costs are *required* to install emissions abatement technologies.

3. Comparisons to EPA Cost Estimates

In the Final Regulatory Impact Assessment (RIA) for CAMR, EPA publishes its own estimates of compliance costs and Hg emission benefits associated with the cap-and-trade program. The results of the EIA analysis are generally consistent with EPA's own and reinforce EPA's conclusion that "a 'cap-and-trade' approach to limiting Hg emissions is the most cost-effective way to achieve the reductions in Hg emissions from the power sector" (70 *Federal Register* 28606). The EIA modeling, however, assumes that the Final Rule would include a safety valve provision of $2,187.50 per Hg allowance (covering one ounce of emission). This means that the government would sell Hg emission allowances to emitters at this price, thus setting a maximum allowance price. The EIA model predicts that, from 2018 on, power companies would choose to purchase mercury allowances at the safety valve price rather than adopting additional control technologies or switching to another variety of coal (EIA 2005, p. 9).

We would expect this assumption to lower the compliance costs and increase the Hg emissions when compared to the EPA analysis, which does not assume a safety valve price. Indeed, Table 3 shows that while costs are higher in the EPA case, emission reductions are also higher; even though EPA's cost estimates do not project to 2025, emissions reductions in 2020 (24.3 tons) are higher than what EIA reports for 2025 (19.8 tons).[8]

Table 3. EPA Estimates of CAMR Compliance Costs and Hg Emission Reductions

	Compliance Cost (a)	Hg Emission Reductions from 1999 Baseline
2010	$0.19 billion	17.3 tons
2015	$0.12 billion	20.7 tons
2020	$0.91 billion	24.3 tons
Present value (2007-2025)	$4.7 billion	N/A

Source: EPA (2005b), pp. 7-5 and 7-7
Note: (a) EPA cost values in 1999$ have been converted to 2006$ using the Consumer Price Index.

4. Implications of Technological Uncertainty

The EIA analysis is also useful in that it shows the effects of uncertainty in one technology discussed to remove mercury, activated carbon injection (ACI), on projected compliance costs. ACI systems have been widely used in such industries as municipal solid waste plants. In applications other than electric utilities, ACI has achieved Hg removal rates of over 90 percent (EIA 2005, p. 7). However, ACI systems are only now being tested for coal-fired generation units, which have several characteristics that may reduce the effectiveness of ACI. For instance, coal plants are much larger, have more flue gas to treat, and emit flue gas that contains lower

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[8] Emissions reductions in the EIA analysis and the EPA analysis are relative to baseline emissions in two different years (2003 and 1999, respectively). Emissions reductions in the two analyses are comparable, however, because the baseline emissions values differ little. The EIA gives Hg emissions in 2003 as 49.99 tons (EIA 2005, p. 39), and the EPA gives Hg emissions in 1999 as 48.6 tons (EPA 2005b, p. 7-5).

concentrations of mercury. Additionally, efforts to remove mercury could lead to damaging, corrosive conditions (EIA 2005, p. 7).

The three additional EIA scenarios characterizing technological uncertainty are as follows.

- "MACT-90": A mandatory 90 percent reduction MACT for all generating units, where it is assumed that ACI is available and able to remove 90 percent of mercury.
- "MACT-Limited ACI": A mandatory 90 percent reduction MACT for all generating units, where it is assumed that the maximum achievable mercury removal for plants using subbituminous and lignite coals is 80 percent.
- "MACT-No ACI": A mandatory 90 percent reduction MACT for all generating units, where it is assumed that ACI technology is not available until 2025.

Table 4 summarizes the EIA modeling results for the three additional scenarios.

Table 4. EIA Results for Alternative Mercury Control Approaches with Technological Uncertainty

	Present Value of Net Costs (a)	Hg Emission Reductions in 2025 from 2003 Baseline
MACT-90	$22 billion	40.1 tons
MACT-Limited ACI	$261 billion	40.1 tons
MACT-No ACI	$358 billion	40.1 tons

Source: EIA (2005), p. 18

Note: (a) The present value of net costs represents discounted resource costs and safety valve payments. Costs cover 2005 though 2025 and are discounted at 7 percent.

The present value of net costs for the "MACT-90" case is ten times greater than for the cap-and-trade approach, and the present values of net costs for the "MACT-Limited ACI" and "MACT-No ACI" case are more than one hundred times greater. Theses results indicate that the cost savings under the cap-and-trade approach compared to the technology-based approach are even greater when technological uncertainties are taken into account.

B. State Mercury Budgets under the Clean Air Mercury Rule

In this section we describe the methodology used by EPA to calculate state Hg emission budgets. The data underlying these analyses were made public by EPA when it promulgated the CAMR Final Rule in March 2005 (EPA 2005d, EPA 2005e).

As noted in Section E above, CAMR sets caps on total Hg emissions from coal-fired power plants in the United States. The national cap for Phase 1 (2010-2017) is 38 tons per year, and for Phase 2 (2018 and thereafter) the national cap is 15 tons per year. States are assigned Hg emission budgets for these two phases that sum to the total national cap.[9] CAMR provides for a national cap-and-trade program that states may join to meet their Hg emissions budgets. If they choose not to participate in the program, their emissions budgets are firm caps.

1. EPA Methodology

State mercury budgets under CAMR are calculated as the sum of emissions allocation to individual coal units in each state. Allocation to individual coal units, in turn, is based on fuel heat input in the period 1998-2002. For most units the average of the highest three years' values is used, but other measurements of fuel input in this period are possible.

In preparation for the CAMR rulemaking, EPA collected information on Hg removal rates for different types of coal and concluded that Hg in the coal ranks can be expected to react differently to control equipment.

> The test data indicated that installation of PM, NO_x, and SO_2 controls on plants burning bituminous coals resulted in greater Hg reduction on average than plants burning subbituminous coals or lignite coals. Likewise, the test data indicated that installation of PM, NO_x, and SO_2 controls on plants burning subbituminous coals resulted in somewhat greater Hg removal than plants burning lignite coals. On average, units burning lignite coal showed the least Hg removal of the three coal ranks (70 *Federal Register* 28622).

For this reason, the following adjustment factors were used for allocation to individual coal units:

- Bituminous units: 1.0
- Subbituminous units: 1.25
- Lignite units: 3.0

Because the national cap is not changed by these adjustment factors, units that burn bituminous coal receive lower emissions allocations than they would otherwise receive.

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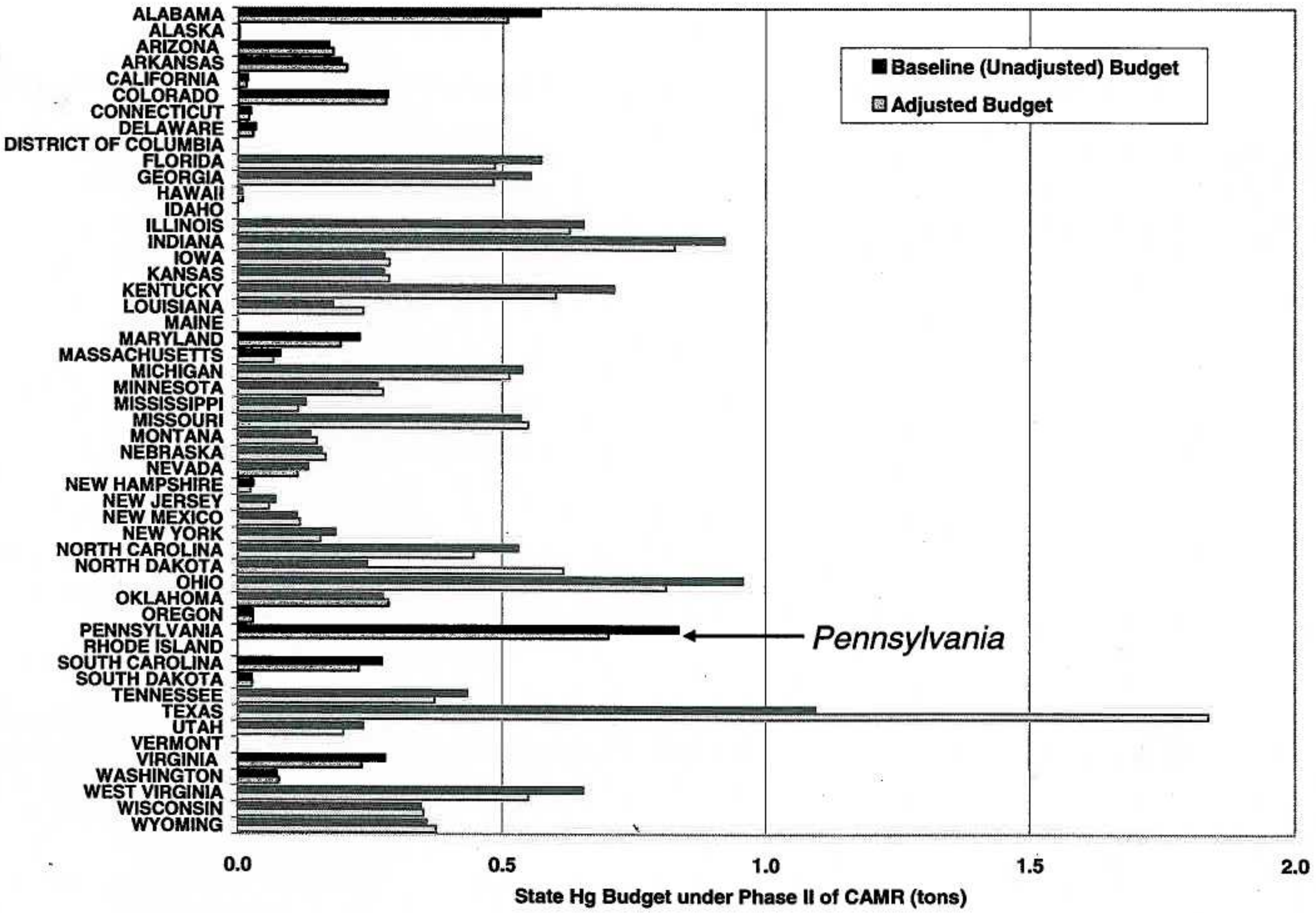
[9] Tribal nations also have Hg emission budgets under CAMR. These are ignored for the sake of simplicity.

2. Emission Budgets by State

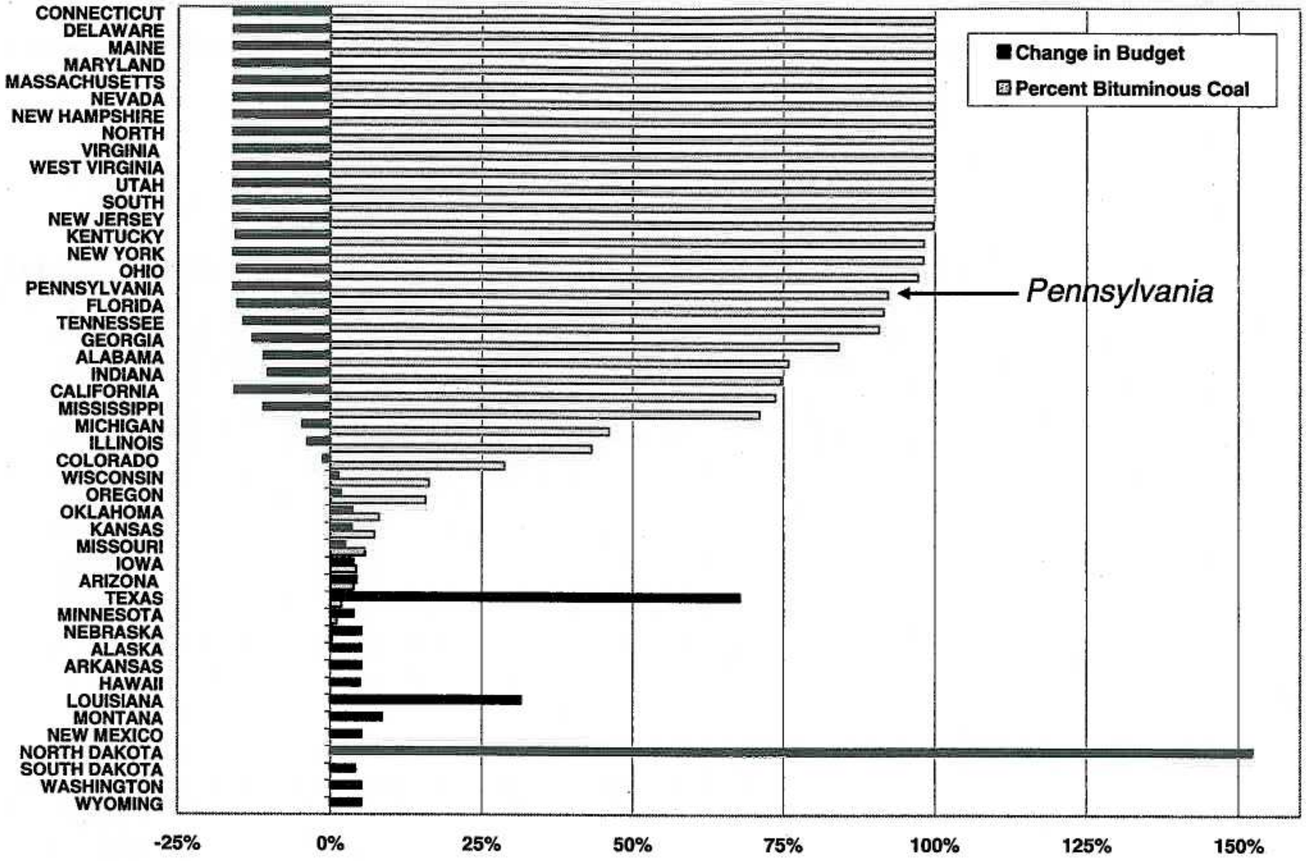
Figure 10 presents Phase 2 Hg emissions budgets by state before and after the coal rank adjustment. Some states' budgets were lowered by the adjustments, while others' were raised.



Source: NERA calculations based on data from EPA (EPA 2005d).

Figure 10. State Hg Emission Budgets under Phase 2 of CAMR

Figure 11 illustrates the relationship between the change in each state's Phase 2 Hg budget and bituminous coal use as a proportion of all coal use in each state. As shown in the figure, states whose coal-fired EGUs burn mostly bituminous coal are those that had their Phase 2 Hg budgets reduced the most by the coal rank adjustment. States whose coal-fired EGUs burn little bituminous coal had their budgets increased.

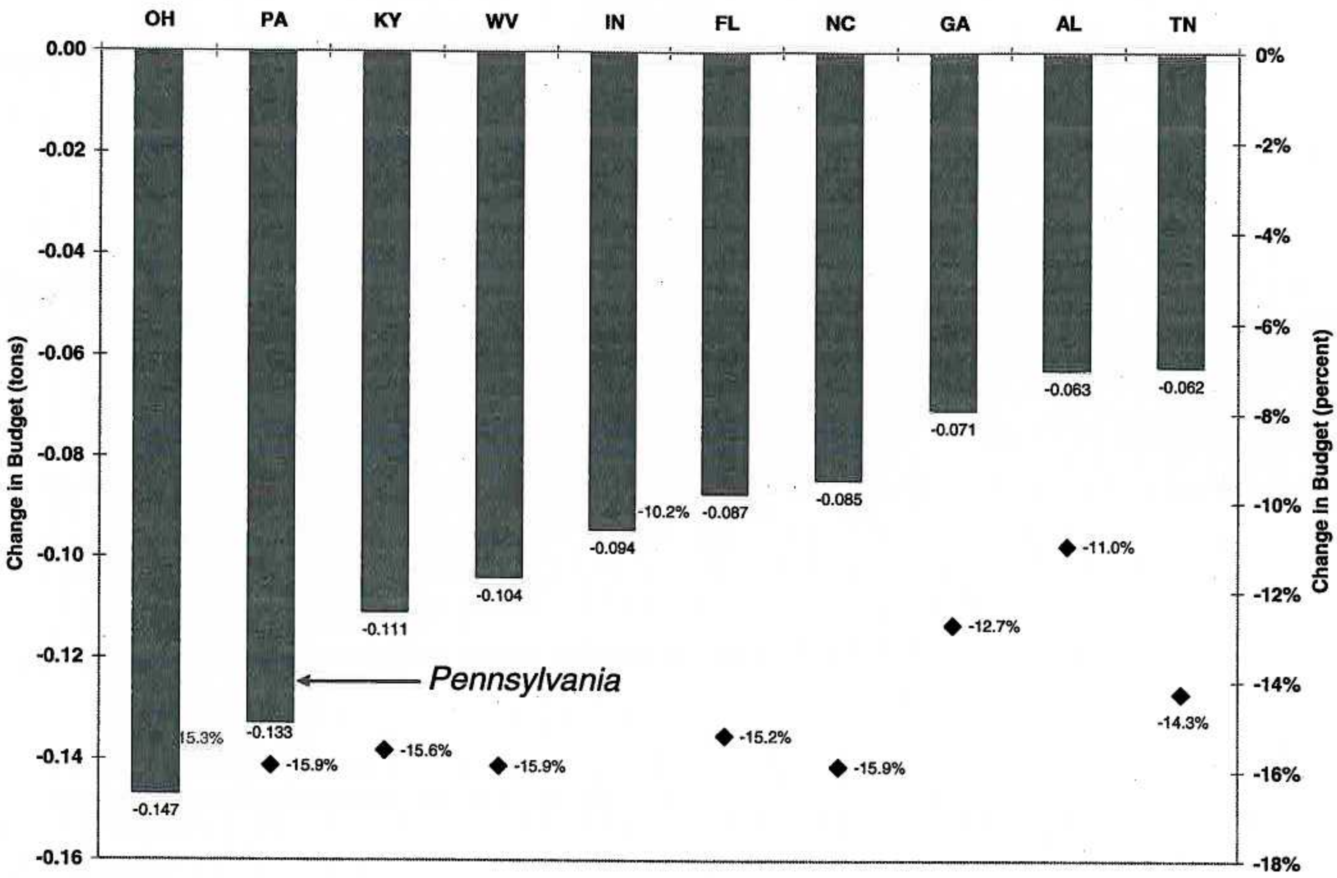


Source: NERA calculations based on data from EPA (EPA 2005d).

Note: The District of Columbia, Idaho, Rhode Island, and Vermont do not appear in this chart because, according to the EPA database, they do not have coal-fired EGUs. The change in the Hg budget is not directly proportional to the percent bituminous coal because it also depends on the percent subbituminous and lignite coal.

Figure 11. Change in State Hg Budgets from the Coal Rank Adjustment and Percent Bituminous Coal

Figure 12 shows the ten states that had their Phase 2 Hg budgets reduced the most by the coal rank adjustment. In these states, bituminous coal is the input fuel at most – in some cases, all – of the coal-fired EGUs.



Source: NERA calculations based on data from EPA (EPA 2005d).

Figure 12. Top Ten States for which Coal Rank Adjustment Lowered the State Hg Budget

Pennsylvania ranks second among states that had their Phase 2 Hg budgets reduced by the coal rank adjustment. The coal rank adjustment makes the Pennsylvania budget significantly more stringent than the unadjusted budget would have been.

Figure 13 shows CAMR Phase 2 budgets by state as well as projected emissions under CAIR, normalized to 2020 base case projected emissions (i.e. projected emissions for each state in 2020 without CAIR are set to 1). Note that Pennsylvania's Phase 2 budget represents the third lowest ratio of budget to 2020 base case emissions, after Maine and Maryland. Put another way, Pennsylvania's allocation implies more reductions in mercury emissions under CAIR and CAMR than any other state except Maine and Maryland. If allocations were firm caps and emissions trading were not allowed, Pennsylvania would have one of the strictest emissions limits in the nation. Indeed, EPA's allowance analysis suggests that states such as Pennsylvania

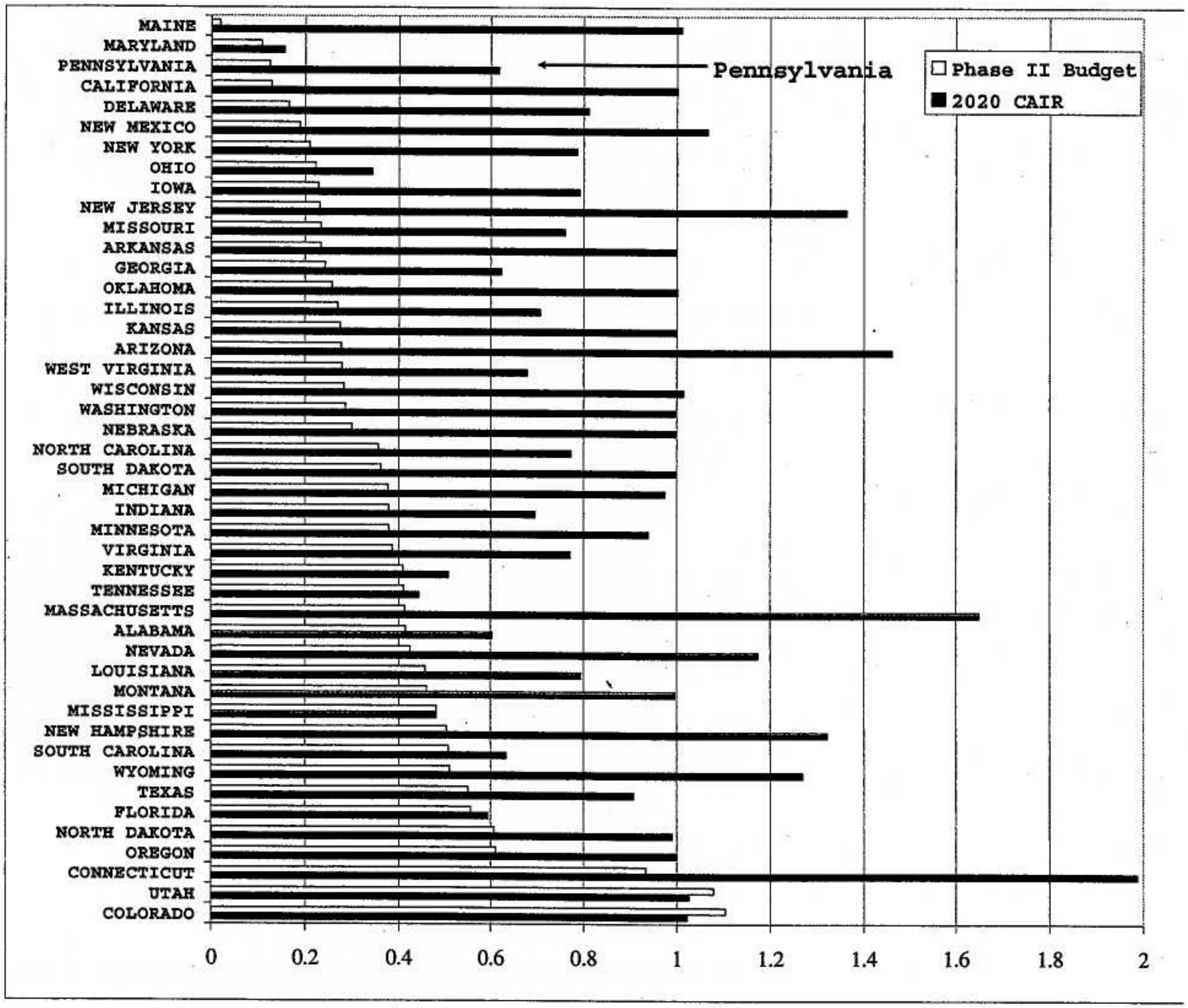


Figure 13. State Phase 2 CAMR budgets and projected mercury emissions under CAIR relative to base-case.

Note: All values are normalized to the state's 2020 base case emissions (year 2020 without CAIR projected emissions equal 1). States not shown here have negligible or zero predicted mercury emissions in the 2020 base case.

Source: NERA calculations based on data from EPA (EPA 2005d, EPA 2005e).

(with EGUs burning mostly bituminous coal) would be net buyers of allowances because they would not be able cost-effectively to achieve their budget allocation with in-state controls.

V. Analysis of the Potential Effects of Mercury Emissions Trading in Pennsylvania

This section provides information on the potential cost savings to Pennsylvania EGUs of relying upon the national emissions trading program for mercury established under CAMR rather than eliminating emissions trading as a compliance option. We consider an alternative rule that would allow participation in CAMR and would also specifically regulate emissions of *oxidized* mercury on a unit-by-unit basis. The empirical portions of these analyses apply to Brunner Island SES, a coal-fired power facility in East Manchester Township, Pennsylvania.

A. Background on the Potential Pennsylvania Rule

Pennsylvania is considering a mercury rule that does not include any trading of allowances (neither intrastate nor interstate). From 2010-2014, pulverized coal burning facilities would need to demonstrate at least one of the following:

(1) A mercury emissions standard of 0.024 lbs. mercury (Hg)/Gigawatt hour (GWh) of generation.

(2) A minimum of 80 percent control of total mercury as measured from the mercury content in coal as fired.

(3) Installation of a Cold-Side Electrostatic Precipitator (CS-ESP) or Fabric Filter (FF) and a Wet Flue Gas Desulphurization (WFGD) unit.

From 2015 onward, pulverized coal-burning facilities would need to demonstrate at least one of the following:

(1) A mercury emissions standard of 0.012 lbs. Hg/GWh of generation.

(2) A minimum of 90 percent control of total Hg as measured from the mercury content in the coal as fired.

(3) Installation of Selective Catalytic Reduction (SCR) technology and WFGD, in addition to a CS-ESP or FF.

The Pennsylvania Rule also includes provisions that allow EGUs to apply for alternative emission standards on the basis that the Pennsylvania rule includes requirements that are "technologically or economically infeasible" (Pennsylvania EQB 2006). In addition to meeting one of the above requirements, facilities must also comply with the CAMR allocations. Under the Pennsylvania Rule, facilities would be issued non-tradable allowances, allocated from the EPA CAMR budget for the state of Pennsylvania. Because neither interstate nor intrastate trading would be allowed, the CAMR allocations would function as unit-by-unit emissions caps. Based on calculations performed by URS, the Brunner Island units would need to capture approximately 88-90 percent in Phase 1 (2010-2014) and 96-98 percent in Phase 2 (2015 on) of total mercury based on the mercury content of the inlet coal in order to achieve the reductions necessary to meet their allocation-based caps. This suggests that the allocation-based unit-by-unit cap resulting from having to meet the CAMR allocations without trading will be more stringent than any of the three compliance line items specified in the Pennsylvania Rule. Henceforth, we refer to the Pennsylvania Rule as requiring at least 96 percent reduction from inlet mercury in Phase 2, and will not consider the other compliance items, as they are superseded by the requirement to comply with the CAMR allocations on a unit-by-unit basis. The empirical analysis presented here is specific to Phase 2 of the Pennsylvania Rule (2015 and thereafter), although similar conclusions should apply to Phase 1.

B. General Economic Concerns Regarding Proposed Pennsylvania Rule

The proposed Pennsylvania Rule raises four concerns related to the costs and benefits it would yield in Pennsylvania. These concerns correspond to the numbered items in Figure 14, which illustrates these issues through a marginal abatement cost curve for a hypothetical Pennsylvania power plant. The total cost for reaching any level of mercury emissions (i.e., reducing emissions below the "baseline" level) is shown as the area under the marginal cost curve. Under emissions trading, the cost per pound is limited by the allowance price. If emissions trading is not allowed, however, there is no limit to the cost per pound that the power plant may incur to reduce mercury emissions.

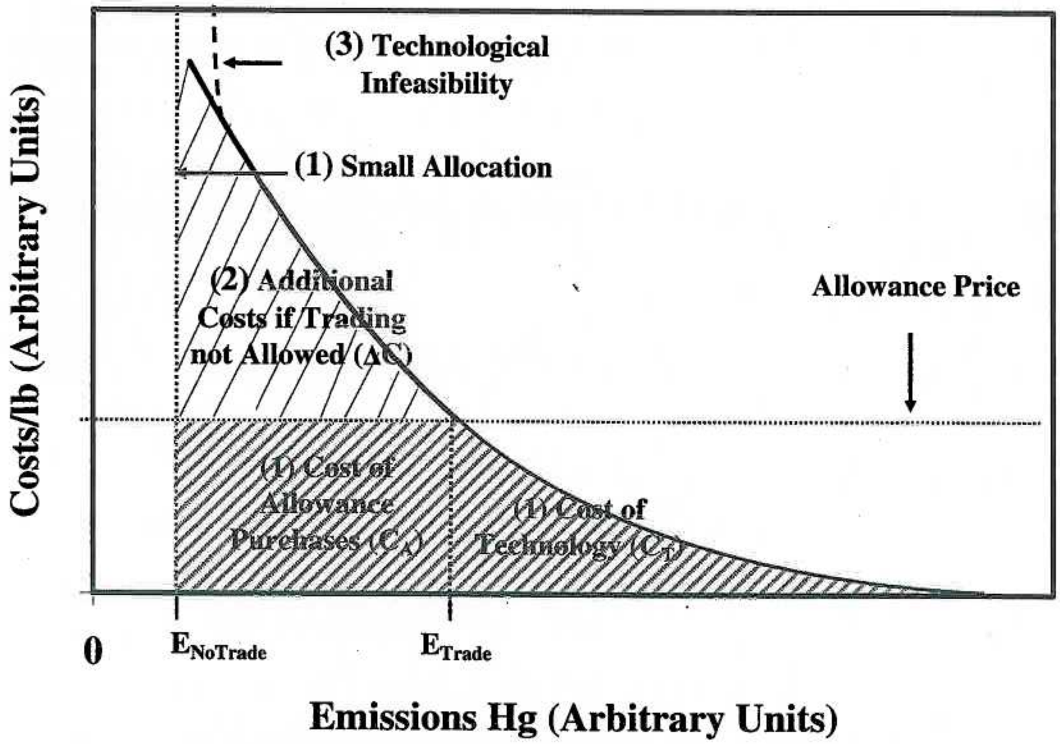


Figure 14. Illustration of several issues raised by proposed Pennsylvania mercury rule. (1) a small allocation; (2) additional compliance costs due to ban on trading of allowances; and (3) a potential infeasibility due to small allocation.

The four main concerns can be summarized as follows.

(1) *The Pennsylvania mercury budget under CAMR is small and thus compliance costs are large even with emissions trading.* CAMR requires substantial percentage reductions in mercury emissions, particularly for Pennsylvania units. Due to a coal-rank adjustment used by EPA in determining mercury allocations, states with EGUs that burn mainly bituminous coal received smaller budgets than they would have otherwise. Since Pennsylvania EGUs burn almost exclusively bituminous coal, Pennsylvania's mercury budget adjustment was large and unfavorable. The net effect of the stringent CAMR target and the adverse coal-rank adjustment is large compliance costs for Pennsylvania units, even under emissions trading. The area shaded in pink in Figure 14 illustrates the cost under CAMR with Pennsylvania's relatively small allocation. Note that these high costs are a result of the CAMR allocation rather than the Pennsylvania Rule.

(2) *Disallowing emissions trading could raise compliance costs substantially.* The proposed Pennsylvania Rule does not allow emissions trading, and thus affected units must meet the CAMR allocation as a firm cap. Put another way, disallowing trading means that there is no limit to the cost per ton that a Pennsylvania unit would have to pay to meet the Pennsylvania Rule. Disallowing trading thus exacerbates the high costs to Pennsylvania units under CAMR, perhaps substantially. The area shaded in blue in Figure 14 illustrates the substantial additional costs to the Pennsylvania unit due to the prohibition on emissions trading under the Pennsylvania Rule. Note that these increased costs do not lead to any additional national mercury emission reductions; the prohibition on trading simply leads to higher compliance costs.

(3) *The CAMR Phase 2 allocations, if enforced as firm caps, may be technologically infeasible.* The Phase 2 allocation equates to approximately 96 (or greater) percent capture of mercury in inlet coal, a level that may be infeasible for some generating units given current technology (see URS, 2006). The dashed line for the marginal cost curve in Figure 14 illustrates a case in which the illustrative Pennsylvania unit could not achieve the stringent cap on its own, regardless of the cost it incurs. Because the Pennsylvania Rule provides no flexibility for units that cannot meet their cap to purchase allowances from those that can over-control, this infeasibility on the part of some units may result in Pennsylvania exceeding its CAMR Phase 2 budget, thereby raising national emissions above the CAMR cap.

(4) *The proposed Pennsylvania Rule cites concerns about local deposition, but does not specifically regulate the species of mercury that deposits locally.* Mercury is emitted from EGUs as several distinct species, notably oxidized mercury and elemental mercury. However, oxidized mercury is the only species that contributes to local deposition in Pennsylvania (see ENVIRON, 2006). Based on data provided by URS, emissions of oxidized mercury can be reduced to stringent limits at a reasonable cost. Thus, most of the high costs illustrated in Figure 14 represent costs to reduce elemental mercury; these costs would not yield any reductions in Pennsylvania deposition. Moreover, national emissions would be essentially identical regardless of whether the proposed Pennsylvania Rule was enacted or Pennsylvania units were simply regulated by CAMR. Thus, the large costs

imposed on affected units by the Pennsylvania Rule would yield no additional environmental benefits.

C. Overview of the Empirical Analysis

We consider a regulatory alternative ("Alternative Approach") that would address concerns about the level of local mercury deposition in Pennsylvania by specifically regulating emissions of *oxidized* mercury on a facility-by-facility basis. We have developed estimates of costs and emissions for this Alternative Approach as well for the Pennsylvania Rule as reflected in a single large PPL electricity generating unit (Brunner Island Power Plant). This comparison illustrates what is at stake in terms of overall Pennsylvania mercury emissions and compliance costs for Pennsylvania facilities by selecting the Pennsylvania Rule rather than the Alternative Approach.[10]

NERA used detailed plant-level data developed by URS to estimate the cost to Brunner Island of complying with either the Pennsylvania Rule, or participating in trading under the CAMR Phase 2 rule with an additional requirement to reduce oxidized mercury emissions by 90 percent from uncontrolled levels ("Alternative Approach"). Under the Alternative Approach, Brunner Island would be able to buy and sell allowances freely on the national market, subject to the requirement that it installs technology that achieves 90 percent or greater reduction of *oxidized* mercury emissions from uncontrolled levels.[11] Under the Pennsylvania Rule, in contrast, there is no specific regulation on emissions of oxidized mercury, and no trading of allowances would be permitted.

The empirical assessment of the potential gains of allowing interstate trading in mercury allowances follows the conceptual framework outlined above. We analyze a representative year in CAMR Phase 2 (in this case, the year 2020). Note that although we do not provide empirical comparisons for Phase 1, we would expect the results and general conclusions to be similar to those we develop for Phase 2. The Phase 1 CAMR allocation to Brunner Island implies a reduction from inlet mercury of 88-90 percent (see URS 2006). The allocation is therefore the most stringent element of the Pennsylvania Rule in Phase 1 as well as Phase 2. Moreover, control technology decisions for Phase 1 would take into account expectations in Phase 2 (see D.4 below for a discussion of the additional costs of the Pennsylvania Rule due to the lack of flexibility between Phase 1 and Phase 2 controls). As a result, Brunner Island would likely install the technology expected to be required for Phase 2 during Phase 1, and thus annualized costs would be similar under the Pennsylvania Rule in both phases. Annualized costs in Phase 1 for the Alternative rule would likely be lower than the costs for Phase 2 due to the larger allowance allocation.

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[10] A complete analysis would include estimates for all of the Pennsylvania EGUs covered by the mercury requirements. Results for Bruner Island, however, are likely to be representative of results for other Pennsylvania EGUs subject to the Pennsylvania rule. In particular, the types of controls expected to be installed at Bruner Island due to the CAIR requirements—which form the baseline for estimating the additional costs due to mercury requirements—are likely to be similar to those expected to be put in place under CAIR at other Pennsylvania EGUs.

[11] We would expect the mandatory percentage reduction in oxidized mercury to apply only to large units.

1. Scope of the Analysis

NERA's analyses in this Report focus on Brunner Island, which has three separate bituminous-fired generation units.

- Brunner Island 1: 348 MW generation capacity;
- Brunner Island 2: 404 MW generation capacity; and
- Brunner Island 3: 778 MW generation capacity.

Using information provided by URS, NERA developed a detailed plant-level database for Brunner Island. The information in the database falls into the following three categories.

(1) Basic information on the facility;

(2) Cost and emissions information for the potential control technologies; and

(3) Information on control technologies already installed or planned for installation as a means of CAIR compliance.

The plant-level data include, among other things, information on location, size, fuel use, and both current and potential future control technologies. The data also include baseline annual inlet mercury at each unit. In addition, the data include both the projected costs—including capital costs and annual operating and maintenance (O&M) costs—and the expected mercury emission rates for a variety of control technologies.[12]

Table 5 shows average Hg content in coal and annual Hg inlet in fuel (assuming operation at 80 percent capacity) for the three units at Brunner Island.

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[12] Technologies installed or planned for installation as a means of CAIR compliance are included in the database at zero cost.

Table 5. Baseline Information on Mercury Emissions from Brunner Island.

Unit	Average Hg in Coal (lbs/Tbtu)	Rated Heat Input (mmBtu/hr)	Annual Hg in Fuel at 80% Capacity (lbs)
Brunner Island 1	21.8	3,314	506
Brunner Island 2	21.8	3,825	584
Brunner Island 3	21.8	7,239	1,106
Total	-	**14,378**	**2,196**

Source: URS (2006)

Emission caps and allowance allocations under the Pennsylvania Rule and the Alternative Approach are the following[13]:

(1) *Limit on Total Mercury Emissions.* The Pennsylvania Rule, by requiring CAMR compliance with no trading, would effectively limit total mercury emissions from Brunner Island to 90 lbs/year, the equivalent of a 96 percent (or possibly greater) reduction from mercury in the inlet coal. The Alternative Approach does not specifically limit *total* mercury, but requires CAMR compliance through some combination of emissions trading and installation of control technologies.

(2) *Limit on Oxidized Mercury.* The Pennsylvania Rule would not set a specific limit on emissions of oxidized mercury. We assume that the Alternative Approach requires reduction of oxidized mercury emissions by 90 percent at Brunner Island relative to uncontrolled levels.

(3) *Allowance Allocation.* In both cases, the allowance allocation to Brunner Island is 90 lbs (in Phase 2, 2015 and thereafter).

2. Control Technologies

The empirical analysis is based on estimates of the costs of various control technologies, and their maximum level of effectiveness expressed as a percentage reduction from the mercury content of inlet coal (see URS 2006). For the purposes of compliance cost calculations, the baseline is the configuration of the plant expected under CAIR, that is, technologies installed for CAIR compliance are counted as zero cost. Table 6 shows the technologies assumed to be installed at the three Brunner Island units due to CAIR, and the associated estimates of reduction

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[13] See URS (2006) for calculation of allocation to each unit.

from uncontrolled levels of oxidized mercury and total mercury content in coal for total mercury as provided by URS.[14]

Table 6. Technologies installed for CAIR compliance.

Unit	Technology Configuration Under CAIR	Total Mercury Reduction from Hg in Coal	Oxidized Mercury Reduction (% of Uncontrolled Emissions of Oxidized Hg)
Brunner Island 1	Wet Scrubber + Fabric Filter	65%	≥90%
Brunner Island 2	Wet Scrubber + ESP	40%	≥90%
Brunner Island 3	Wet Scrubber + ESP	40%	≥90%

Source: URS (2006)

The database includes the following two mercury-specific control technologies for Brunner Island (URS, 2006 p.24).

- Chemical addition + FGD additive (referred to as "chemical addition" herein);[15] and
- Toxecon™.

Table 7 shows assumptions regarding maximum achievable control levels for the mercury-

Table 7: Maximum achievable emissions reductions for Mercury-specific control technologies.

Technology	Maximum Achievable Emissions Reduction
Chemical Addition + FGD additive	90%
Toxecon™	96%

Source: URS (2006).

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[14] Note that reductions in total mercury are expressed as percentages of the total mercury in the inlet coal, and reductions of oxidized mercury are expressed as percentage reductions from uncontrolled emissions of oxidized mercury.

[15] Although other technologies are provided in URS (2006), they are not cost-effective relative to Chemical addition + FGD additive and therefore were not considered in this analysis.

specific control technologies included in this analysis. Descriptions of the technologies, as well as capital and O&M cost estimates and confidence assessments, are provided in the URS (2006).

3. Conceptual Framework for Marginal Abatement Cost Curve

In order to construct marginal abatement cost curves for Brunner Island under the two scenarios considered, we use cost and emissions data provided by URS. A linear optimization algorithm selects the least-cost technology configuration for a range of marginal abatement costs sufficiently broad as to represent the entire technological implementation set. This procedure generates directly a marginal abatement cost curve (MACC).

Figure 15 gives a graphical representation of an example MACC and illustrates the selection of optimal control technology. The figure shows three possible technologies—labeled T_1, T_2, and T_3—that could reduce emissions from the "business-as-usual" baseline level (E_0), i.e., the emissions from the unit that would occur in the absence of any additional controls. The technologies are arranged in terms of their cost-effectiveness, i.e., the dollars per pound of emissions reduced.

a. Unit Regulated by Cap-and-Trade

Given an allowance price of p and the allocation indicated in Figure 15, a unit participating in a cap-and-trade program would choose to install control technologies T_1 and T_2 but not technology T_3.[16] The unit would reduce its emissions from baseline emissions (E_0) to controlled emissions (E*) at total technology cost equal to TC (in general, the total cost is the area under the MACC). It would then purchase allowances to cover the difference between E_0 and its allocation, at a cost of AC.

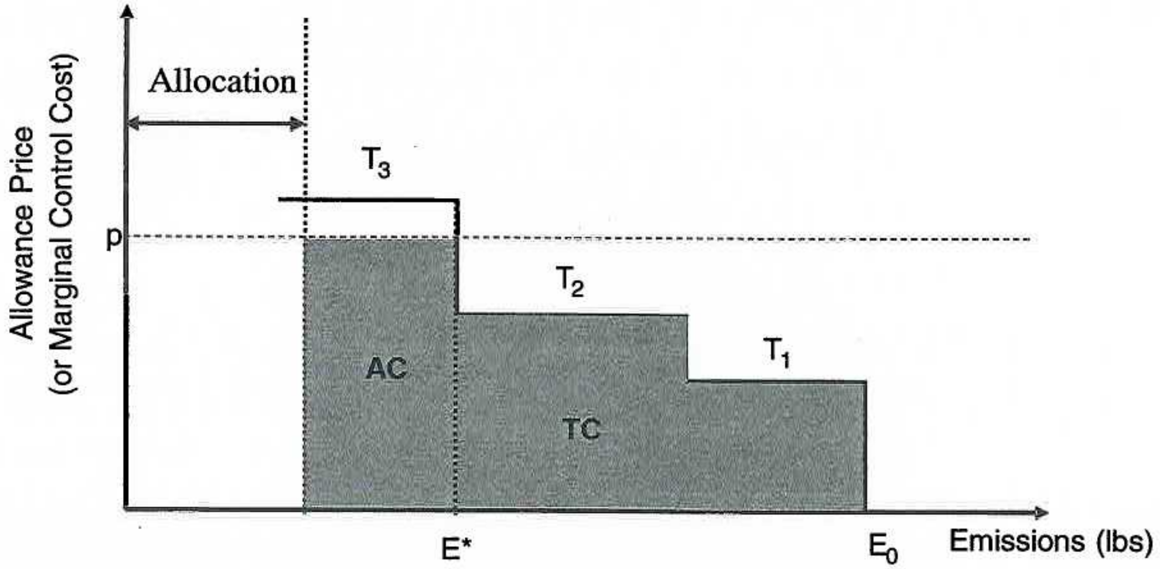

Figure 15. Illustration of Cost Minimization Decision for Unit Regulated by Cap-and-Trade

b. Unit Regulated by Command-and-Control

Figure 16 represents the same unit, subject to a regulation that does not allow trading, but is otherwise identical to that analyzed in Figure 15. The unit must reduce its emissions to the level covered by its allocation. Controlled emissions (E*) are now the same as the emissions implied by the allocation. Although national emissions are the same in both instances, costs will always be higher for the unit regulated by command-and-control, assuming that the allowance cost is less than the marginal cost of installing T_3. In the case of a unit for which the allocation implies an emissions level that is technologically infeasible, the emissions would actually be higher nationally compared to the cap-and-trade scenario. These several observations apply to the Pennsylvania Rule, in which the allocation is the most restrictive element of the regulation and emissions trading is not allowed.

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[16] This is because the allowance price is less than the marginal cost of technology T_3.

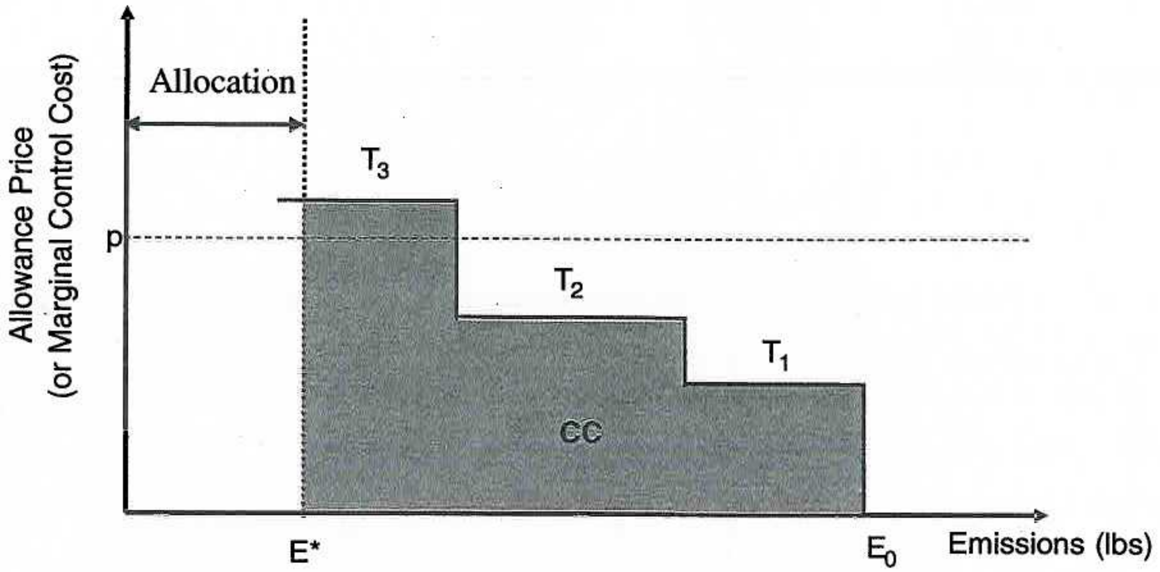

Figure 16: Illustration of MACC for Unit Regulated by Allocation "Cap"

D. Empirical Analysis of Costs for Brunner Island Facility under Pennsylvania Rule and Alternative Approach

1. Assumptions of Empirical Analysis

Our analyses of the Alternative Approach assume that Brunner Island would be free to buy and sell allowances subject to the cap, provided that it achieves a 90 percent reduction of oxidized mercury from uncontrolled levels. Since the CAIR technologies for each unit are projected to achieve this level of reduction in oxidized mercury, the 90 percent reduction requirement is achieved at no compliance cost. In the Pennsylvania Rule, allowances may not be bought or sold. Excess allowances are sold on the market each year in the Alternative Approach (to simplify the cost analysis, our model does not allow banking of allowances). To develop marginal and total costs for complying with each regulation, we have used cost data provided by URS (see URS 2006, p. 24-25). We represent these costs as annualized costs for a representative year in Phase 2 of each regulatory approach. We assume a capital amortization period of 15 years at 7 percent for chemical addition, and amortization of 30 years at 7 percent for Toxecon^{TM}.

The implication of these assumptions is that all estimates in the Alternative Approach assume "perfect trading," i.e., that Brunner Island would achieve the given cap in the least-cost manner. We also assume that due to the size of the national market, Brunner Island would take the allowance price as given. We use the EPA estimates of average allowance prices in the different periods to calculate the potential gains from trading and control decisions in the Alternative Approach, assuming that excess allowances would be sold at the market price. EPA projections of allowance prices are shown in Table 8.

Table 8: Projected Mercury Allowance Prices

Year	Projected Allowance Price (thousands$/lb) [(a)]
2010	$28.00
2015	$36.50
2020	$47.25

Source: EPA (2005c), p. 31
Note: (a) EPA projected prices in 1999$ have been converted to 2006$ using the Consumer Price Index

2. Marginal Abatement Cost Curve for Brunner Island Facility

Shown below is an aggregate marginal abatement cost curve (MACC) for the Brunner Island facility. Note that reductions up to approximately 45 percent from total mercury in coal can be achieved at no cost (i.e. as a co-benefit of CAIR). Further reductions can be achieved at relatively low cost by installing chemical addition technology. This technology reaches its theoretical limit at approximately 90 percent reduction from inlet mercury (220 lb. aggregate emissions). To achieve additional reductions, Toxecon™ can be installed on the Brunner Island units. This technology is relatively high cost, and corresponds to the spike in the MACC from a marginal cost of approximately $4,000/lb-$6,000/lb. to a marginal cost of approximately $100,000/lb. This step in the marginal cost curve is indicated by an arrow in Figure 17. The projected allowance price in 2020 is shown as a horizontal dashed line, and the aggregate allocation to Brunner Island is shown as a vertical dashed line.

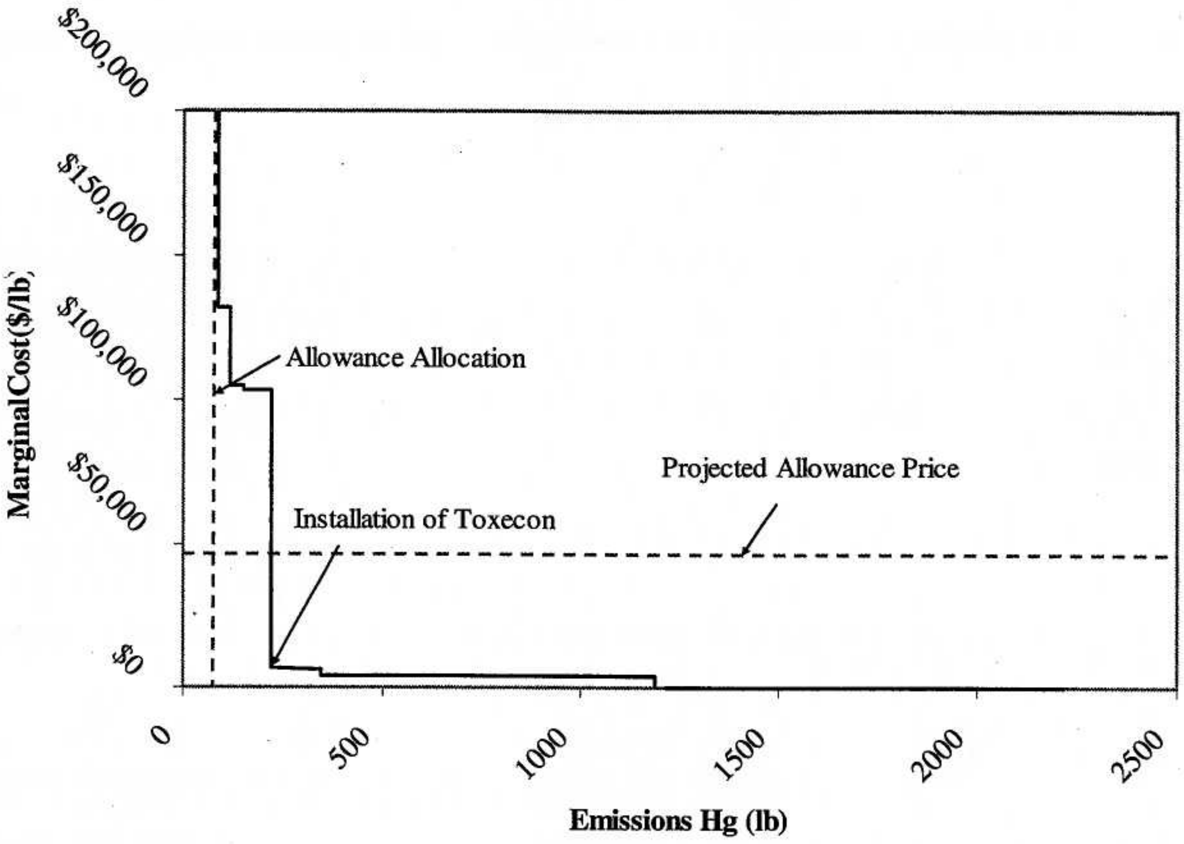

Figure 17: Marginal cost curve for Brunner Island facility.

Soure: URS (2006), and NERA calculations as explained in text.

3. Costs and Emissions at Brunner Island under Alternative Regulatory Scenarios

URS estimates that at least a 96 percent reduction from inlet mercury will be required to meet the CAMR Phase 2 allocation as a hard cap at the Brunner Island facility. The following section shows cost and emissions estimates, as well as likely compliance strategies, for the two regulatory approaches.

(1) **Pennsylvania Rule.** Figure 18 shows the resulting emissions and costs when the Pennsylvania Rule is applied at Brunner Island. Costs and emissions, both total and incremental, are provided in tabular form in Table 9.

(2) **Alternative Approach.** Figure 19 shows the same information for a regulation that requires 90 percent reduction of oxidized mercury from uncontrolled levels at Brunner Island and is otherwise identical to CAMR. Costs, emissions, and incremental costs and emissions are provided in Table 9.

Table 9: Summary of Emissions and Costs under the Pennsylvania and the Alternative Approach

	Pennsylvania Rule	Alternative Approach
Emissions Total Hg (lbs)	88	220
% Reduction From Hg in Coal	96%	90%
Annualized Technology Costs (Millions$) ($C_T$)	$18.7	$4.2
Allowance Allocation (lbs)	90	90
Cost of Allowances (Millions$) ($C_A$)	$0.0	$6.1
Total Costs (Millions$) ($C_T$+$C_A$)	$18.7	$10.3
Incremental Costs (Millions$)	$8.4	$10.3
Incremental Costs per Pound (Thousands$/lb)	$63.7	$10.6

Source: URS (2006), and NERA calculations as explained in text.

a. Pennsylvania Rule

Under the Pennsylvania Rule, Brunner Island units would have to comply with their CAMR allocations as a unit-by-unit cap. The aggregate allowance allocation is indicated here as a dashed blue line. To achieve compliance, Brunner Island units would install Toxecon™, at total costs represented by the diagonally hatched area under the MACC ((C_T), see Figure 18 below). Emissions of Total mercury are 88 lbs., a 96 percent reduction from mercury in coal. Total annual compliance costs are $18.7 Million annually.[17]

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[17] This cost assumes that the Toxecon™ technology would actually achieve the reduction in total mercury emissions necessary to comply with the CAMR allocation as a firm cap. If this level of efficiency were not achieved, marginal cost and average incremental costs would be higher. Moreover, this would introduce issues of technological infeasibility discussed in Section V.B.

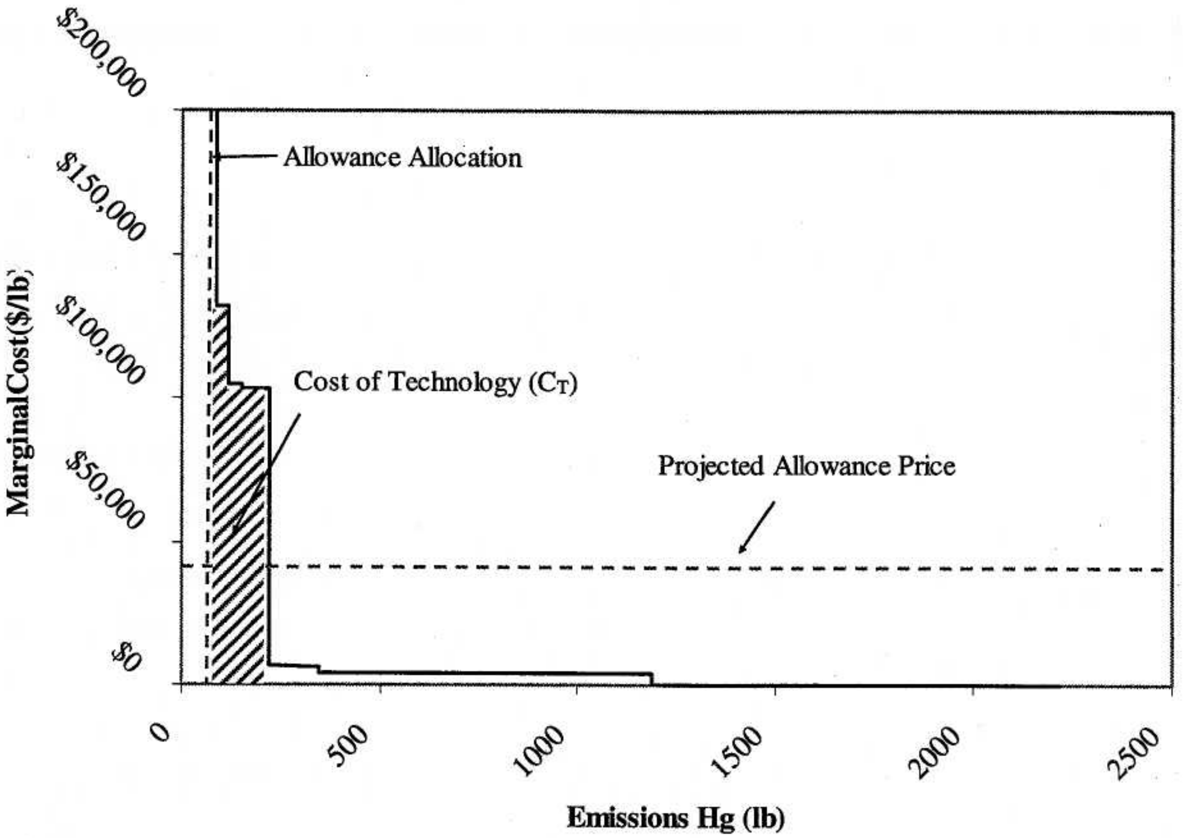

Figure 18: Marginal cost curve for Brunner Island, showing costs under Pennsylvania Rule.

Note: Costs are shown as hatched areas under the marginal cost curve.
Source: URS (2006), and NERA calculations as explained in text.

b. Alternative Approach

Figure 19 shows an aggregate MACC for the Brunner Island facility under the Alternative Approach. Taking into account the expected allowance price, Brunner Island would install chemical addition technology at a cost of approximately $4.2 million annually ($C_T$ in Figure 19), since the cost per pound of mercury reduced is less than the expected allowance price. This technology would achieve approximately 90 percent reduction from inlet mercury (for total mercury emissions of approximately 220 lbs.). Brunner Island would then purchase allowances on the national market to cover the 6 percentage points of inlet mercury by which the facility exceeded its allowance allocation, at a cost of $6.1 Million ($C_A$ in Figure 19). Total annual compliance costs (including purchase of allowances) would be $10.3 Million, roughly half of the total annual compliance costs under the Pennsylvania Rule. Nationally, total mercury emissions would not differ between the Alternative Approach and Pennsylvania Rule.

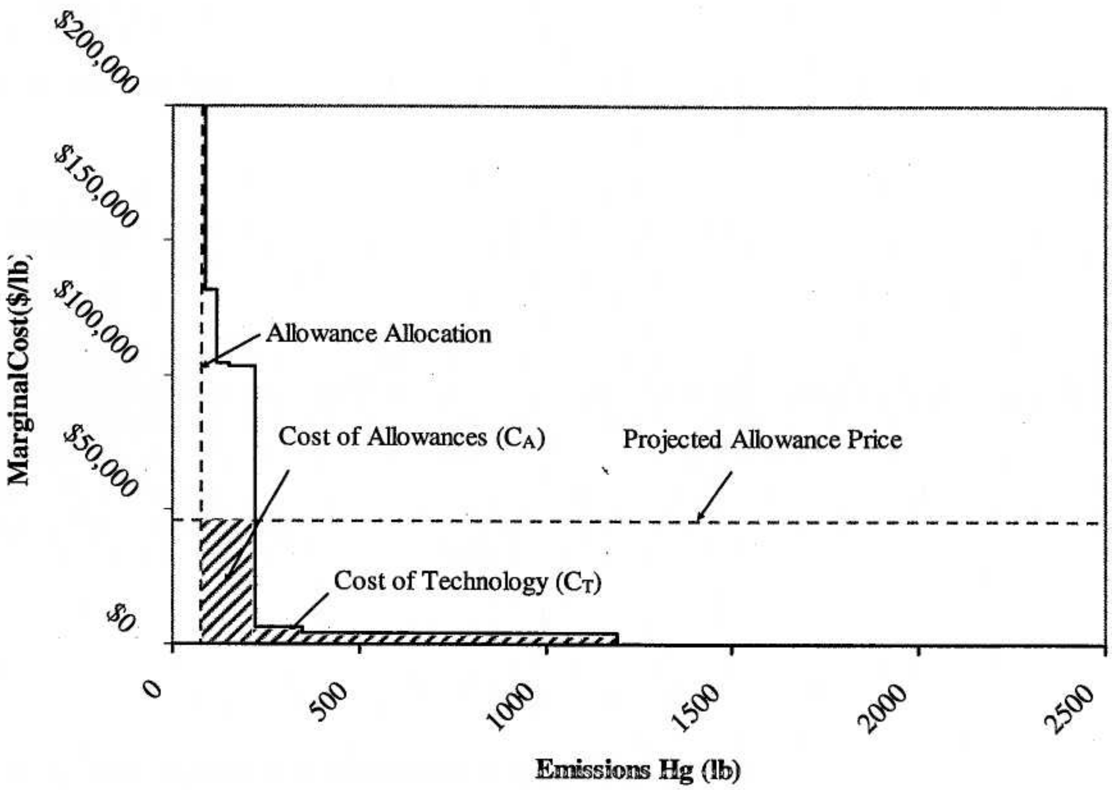

Figure 19: Marginal cost curve for Brunner Island facility, showing costs under Alternative Approach.

Note: Costs are shown as hatched areas below the MACC.
Source: URS (2006), and NERA calculations as explained in text.

4. Inflexibilities and Un-quantified Costs of the Pennsylvania Rule

The empirical cost estimates provided above tend to *understate* the costs of the Pennsylvania Rule because they exclude certain effects of its inflexibility. The following are additional costs due to the inflexibilities of the Pennsylvania Rule that would be avoided under the Alternative Approach.

- *Early installation of expensive controls before they are "needed."* In order to comply with the Pennsylvania Rule, we assume that Brunner Island would install Toxecon^{TM} on all of its units. Since this capital investment is labor and time-intensive, construction would begin prior to the compliance deadline. Moreover, due to uncertainty in the effectiveness of the most cost-effective mercury control technologies (see URS 2006), Toxecon^{TM} is likely the only viable technology option for potentially controlling to the levels required by the Pennsylvania Rule, and may fall short of the required level of control (see URS 2006). Therefore, Brunner Island would not have the flexibility to first attempt to optimize the more cost-effective control technologies; compliance can only be achieved through technology and not through allowance purchases. Thus, Toxecon^{TM} would be installed as early as 2010 (if installation is feasible in this time frame), resulting in additional costs (due to the effects of discounting on the present value of costs) that are not accounted for in our representative year calculations.
- *High-cost technology that is "locked in" without the ability in the future to take advantage of lower-cost alternatives.* Once Toxecon^{TM} is installed on these units, there would be little ability to switch to a lower-cost control technology if it became available. In contrast, trading allows for the flexibility to shift to more cost-effective technologies because of the ability to purchase allowances to meet some of the required reductions, rather than committing to a very expensive and potentially not sufficiently effective strategy now.
- *No incentive to develop more cost-effective control technology.* The Pennsylvania Rule also would not provide incentives to develop more cost-effective control technology, because of the pressure to meet the stringent unit-by-unit requirement with whatever technology is available. In contrast, a cap-and-trade program for mercury creates strong incentives for the development of more cost-effective mercury control technologies over time (see section I and III).

Since these costs are not included in our empirical analysis, our cost estimates underestimate the likely long-run costs and adverse effects of the Pennsylvania Rule.

E. Concluding Remarks

This section identifies a regulatory alternative ("Alternative Approach") that would specifically address concerns about "hot spots" in mercury deposition in Pennsylvania by restricting emissions of *oxidized* mercury at Pennsylvania units—the emissions linked to local deposition—but otherwise allowing Pennsylvania units to take advantage of national trading in mercury allowances. In contrast, the Pennsylvania Rule prevents national trading but provides no specific requirements to restrict *oxidized* mercury. We have developed estimates of the costs of the

Alternative Approach and the Pennsylvania Rule as reflected in a single large PPL electricity generating unit (Brunner Island Power Plant) to illustrate what is at stake in terms of overall Pennsylvania mercury emissions and compliance costs for Pennsylvania facilities by selecting the Pennsylvania Rule rather than the Alternative Approach.

1. Alternative Approach

Pennsylvania would appear to be substantially better off if its plants were able to take advantage of national mercury trading relative to the Pennsylvania Rule that would disallow interstate trading. The Alternative Approach would allow Pennsylvania units to participate in CAMR trading, but would specifically regulate emissions of *oxidized* mercury on a facility-by-facility basis. Modeling by ENVIRON indicates that this Alternative Approach would result in no appreciable difference in local (Pennsylvania) deposition compared to the emissions reductions required by the Pennsylvania proposal (see ENVIRON 2006).

2. Implications of Empirical Analysis for Brunner Island Power Plant

The empirical results for the Brunner Island plant are based on estimates of control costs and effectiveness developed by URS, allowance price projections by the U.S. Environmental Protection Agency (EPA), and assumptions regarding the allocation of initial allowances based upon calculations by URS.

a. Pennsylvania Mercury Emissions

Based on allowance price projections by the EPA and information on the cost of controls at Brunner Island from URS (see URS 2006), Brunner Island is expected to make substantial reductions in total mercury emissions under the Alternative Approach. Although Brunner Island is expected to be a net buyer of allowances, our results suggest that it will reduce emissions of total mercury by approximately 90 percent from total mercury content of the inlet coal, and of oxidized mercury by 90 percent from uncontrolled levels, under the Alternative Approach.

Figure 20 summarizes total annual mercury emissions from Brunner Island under baseline conditions and under the two regulatory cases considered. The figure illustrates that the Pennsylvania Rule would provide very small additional reductions in mercury emissions at Brunner Island, relative to those expected to be achieved under the Alternative Approach. Moreover, emissions of oxidized mercury would not differ substantially between the two scenarios (see URS 2006).

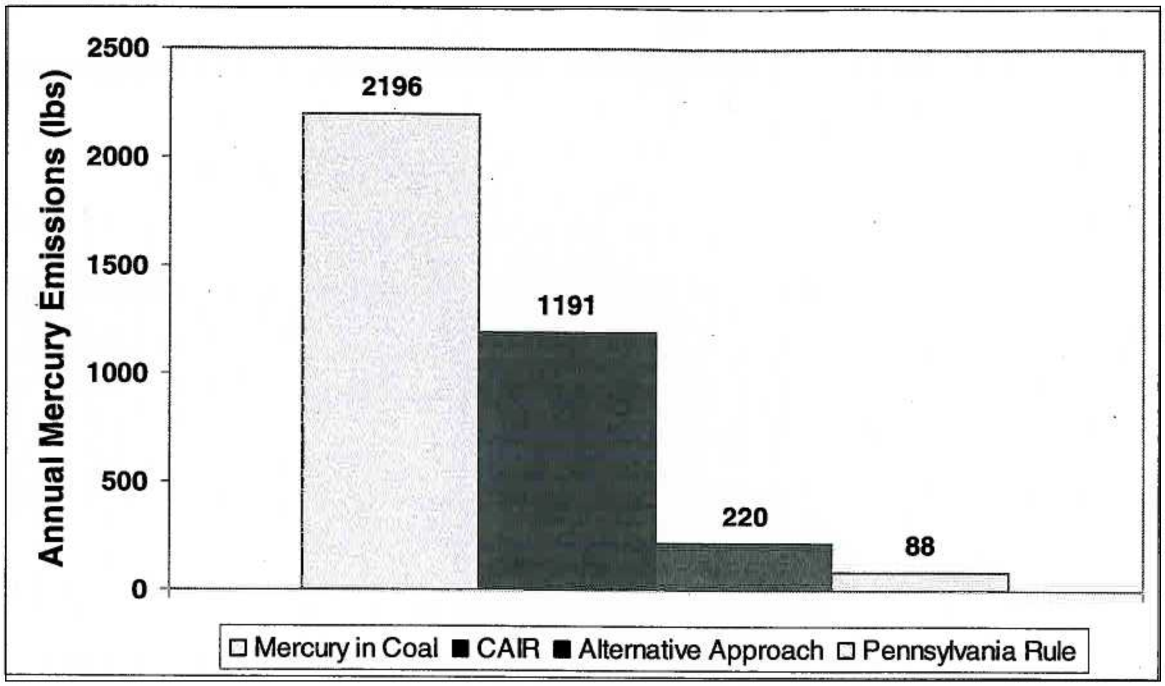

Figure 20. Total Mercury Emissions at Brunner Island in the Baseline and in the Two Scenarios Analyzed
URS (2006), and NERA calculations as explained in text.

Under the proposed Pennsylvania Rule, which from 2015 onward would require compliance with the CAMR Phase 2 allocation on a unit-by-unit basis with no trading allowed, emissions of total mercury would be reduced by about 96 percent from mercury in inlet coal, and emissions of oxidized mercury would be reduced by about 90 percent from uncontrolled levels. Under the Alternative Approach, emissions of total mercury from Brunner Island are projected to be reduced by about 90 percent from mercury content in coal, and emissions of oxidized mercury reduced by 90 percent from uncontrolled levels. (The mercury emissions under the Alternative Approach represent the reductions that would be cost-effective for Brunner Island to make given its marginal cost curve and the projected allowance prices.) Thus, the proposed Pennsylvania Rule would reduce total mercury emissions from Brunner Island by only about 6 percentage points (relative to total mercury content of coal) more than the Alternative Approach. (Note that because of the national cap, there would be *no* difference in *national* mercury emissions between the Pennsylvania Rule and the Alternative Approach.)

b. Pennsylvania Compliance Costs

Cost savings to Brunner Island from being able to participate in interstate trading would be high, because interstate trading avoids the need for Brunner Island to install very expensive controls to achieve the last few pounds of emissions reductions (above and beyond reductions achieved by more cost-effective technology). Indeed, these last pounds require technology at the margin that is estimated to cost more than $100,000 per pound, in contrast to a projected allowance price of less than $50,000 per pound.

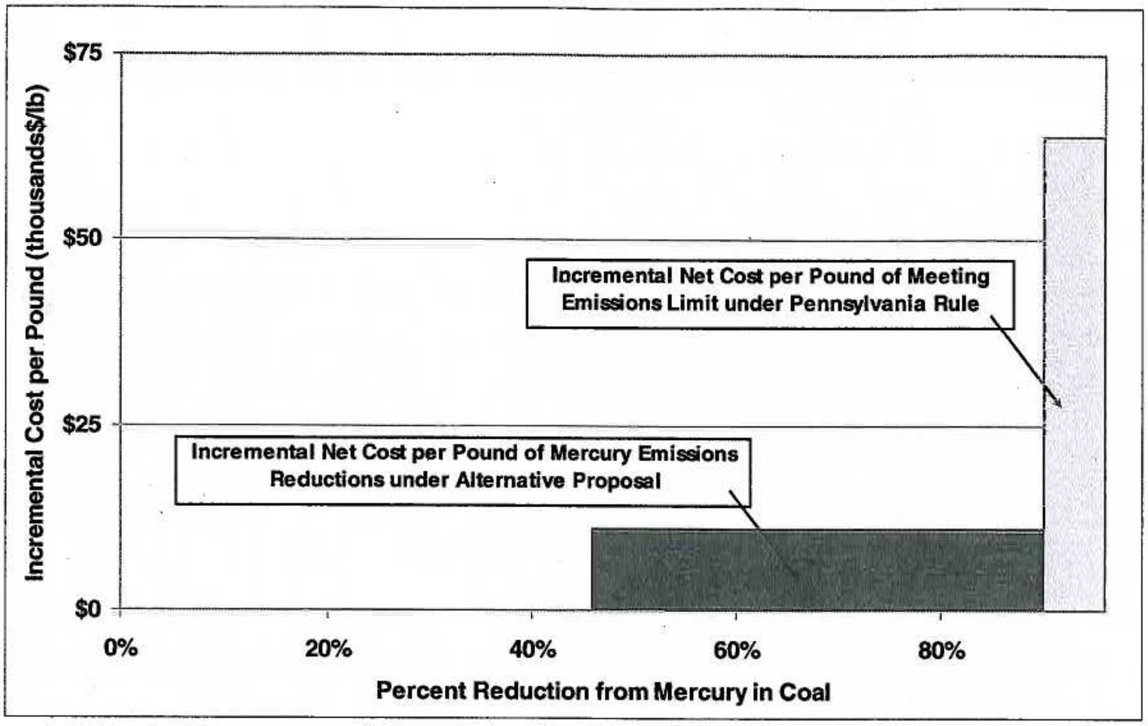

Figure 21. Average Net Cost per Pound of Mercury Emissions Reductions at Brunner Island under Alternative Approach and Average Net Cost per Pound for Additional Reductions under Pennsylvania Rule.

Source: NERA calculations as explained in text.

The average annual costs of achieving total mercury emissions reductions under the two scenarios are illustrated in Figure 21. The costs shown in Figure 21 reflect both the compliance costs to reduce mercury emissions at Brunner Island and the costs of allowance purchases by Brunner Island (in the case of the Alternative Approach). (The allocation of mercury allowances to the Brunner Island units under the Alternative Approach is assumed to be the same as that provided under the Pennsylvania Rule). Figure 21 indicates that the average cost per pound for the additional 6 percentage points of abatement under the Pennsylvania Rule would be high. The rectangle to the right in Figure 21 shows the large additional costs that would be incurred to achieve these small additional mercury emissions reductions at Brunner Island.

3. Conclusions

These empirical results support two major conclusions regarding what is at stake for Pennsylvania if it were to adopt the Pennsylvania rule rather than the Alternative proposal.

(1) Any environmental benefits for the Pennsylvania Rule as compared to the Alternative Approach would be small at best and could be negative. As documented in the ENVIRON report, there would be essentially *no* difference in mercury deposition in Pennsylvania under the two alternatives. Reductions in *total* Pennsylvania mercury emissions expected under the Pennsylvania Rule would be similar to the reductions expected under the Alternative Approach, assuming technology to achieve the stringent Pennsylvania Rule

target were feasible; if the technology to meet the Pennsylvania Rule was infeasible for some sources, national total mercury emissions could *increase* under the Pennsylvania Rule (because of the possibility of an alternative emission standard).

(2) The additional cost of compliance with the Pennsylvania Rule as compared to the Alternative Approach would be very high.

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An Evaluation of Mercury Emissions Reductions in Pennsylvania

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Executive Summary

This paper examines the costs and likelihood of success of achieving mandated mercury reductions at PPL's two Pennsylvania coal-fired electric generating plants -- Montour and Brunner Island (Martins Creek plant is not included as it is scheduled to be shut down in 2007) under three alternative regulatory regimes: (1) achieving reductions in total mercury emissions from the mercury content of the coal to remain within the expected mercury allowance allocation for each unit based on EPA's CAMR without any credit trading; (2) achieving a 90% reduction in the projected uncontrolled *total* mercury emissions at each unit with allowance trading to comply with the unit's budget allocation for total mercury under CAMR; and (3) achieving a 90% reduction in the *oxidized* mercury emissions at each unit based on the amount of oxidized mercury formed during the combustion process and then trading to comply with the unit's budget allocation for total mercury under CAMR.

As shown by PPL's companion study performed by ENVIRON, emissions of elemental mercury from Pennsylvania power plants essentially do not deposit within PA and only a quarter of oxidized mercury emissions deposits within PA. This analysis focuses on the technology and costs to remove (1) oxidized mercury only and (2) total mercury including elemental. Our evaluation shows that achieving the 90% reduction in oxidized mercury at these units is much more certain and much less costly than achieving reductions in total mercury necessary to meet either the 90% total mercury removal requirement or the expected allowance allocations for these units without allowance trading. This is particularly true in light of the variability of the mercury content of the coal used at these units.

Once coal is combusted in the boiler, mercury content of coal is released during the combustion process and is emitted primarily in three distinct forms: particle-bound mercury (Hg^p); oxidized mercury (Hg^{+2}); and elemental mercury (Hg^0). The capability of removing particle-bound mercury is very high at Brunner Island and Montour Stations because all units have either an electrostatic precipitator (ESP) or a fabric filter (FF). Many mercury control technologies rely on particle-bound mercury co-removal in the unit's particulate control device, which is used to collect the ash that forms during coal combustion in the boiler. Most of the DOE testing has been conducted on units that are equipped with large ESPs for particulate emissions control and a smaller number of units equipped with FFs. These devices remove 99% or more particle-bound mercury and all power plants in Pennsylvania are equipped with high efficiency particulate control devices. Therefore, emission of particle-bound mercury is not an issue in Pennsylvania.

Wet scrubbers are capable of capturing the water-soluble oxidized mercury in the flue gas, but remove little or no elemental mercury. Generally, a wet scrubber is able to remove 90% oxidized mercury from the exhaust flue gas. A small amount of the oxidized mercury captured by the scrubber is chemically transformed into elemental mercury and released back into the scrubber outlet flue gas.

With a wet scrubber installed on a given unit, it should be possible to remove 90% of the oxidized mercury without the addition of any add-on control technology. Most of the large power plants in Pennsylvania are either equipped with wet scrubbers or will be installed with wet scrubbers (2008-2012). Any additional control of mercury would require either conversion of elemental mercury to an oxidized form and then removing it with the wet scrubber or removing both elemental and oxidized forms of mercury with a carbon adsorption system.

Selective catalytic reduction (SCR) systems contain oxidation catalysts that not only remove NOx but can also promote the oxidation of elemental mercury to an oxidized form. With the addition of SCR and/or other oxidization technologies, such as use of chemical agents or low-temperature oxidation catalysts, some elemental mercury will be converted to an oxidized form and subsequently be able to be removed by a wet scrubber. Hypothetically, for a unit configured with add-on oxidation technologies, with an assumed 100% conversion of elemental to oxidized mercury, and a wet scrubber capable of removing 90% of the oxidized mercury in the gas, it would be possible to achieve a maximum of 90% total mercury removal. However, 100% conversion of elemental mercury to oxidized mercury has not yet been demonstrated. In fact, these technologies are more likely to have an oxidation effectiveness ranging from 35 to 90+%. The effectiveness of oxidation technologies is highly dependent on coal, boiler design and operation, catalyst efficiency and other plant parameters.

Of key significance is the realization that while increasing the effectiveness of oxidation of mercury increases the amount of total mercury removed, this very process also promotes an increase in the amount of oxidized mercury released to the atmosphere. Removal of oxidized mercury is determined by the effectiveness of the wet scrubber. As oxidized mercury is highly water soluble, wet scrubbers demonstrated the ability to remove 90% of oxidized mercury. This means that, for any amount of elemental mercury that is oxidized, approximately 10% may be emitted as oxidized mercury, so that the total amount of oxidized mercury actually *increases* due to the oxidation of the elemental mercury.

As noted above (1) with the installation of wet scrubbers, the units are fully expected to achieve 90% removal of the oxidized mercury and (2) with the addition of highly efficient oxidation technologies it may be possible, though it is not certain, that they may be able to achieve 90% removal of the total mercury. Even more uncertain would be the ability to meet the expected mercury emissions cap for each unit imposed by the Pennsylvania DEP regulation, (which allocations are to be based on EPA's mercury budget for Pennsylvania). This is because the mercury control efficiencies required to meet the expected allocations are expected to be in 95 to 96% range for the 2015 requirement and 85% to 90% for the 2010 requirement, depending on the mercury content of the coal which can vary significantly. In fact, with the high variability in mercury content in the coal that PPL burns at its Pennsylvania units, the required level of removal could be as high as 98% to meet the 2015 allowance allocation. This is the level of control that would have to be installed even if coal with such high mercury content is burned very infrequently. Of concern is that there is no commercially demonstrated technology available at this time that can achieve this level of reduction.

One technology that holds some potential promise but is far from guaranteed to achieve such high levels of control is an activated carbon injection (ACI) system based on carbon adsorption technology. These systems have not been used in medium to high sulfur coal applications and the range of performance to date has been from 70% to 90%.

Further complications arise from the presence of appreciable levels of activated carbon with captured mercury in fly ash or in synthetic gypsum that may result with the use of ACI technology. If the use of ACI technology results in the contamination of the fly ash or gypsum making either unusable for resale or beneficial applications, then landfills will need to be developed or mine reclamation utilized, typically at unacceptable economic penalty. To avoid any such contamination to fly ash the only mercury control technology that has the potential for achieving greater than 90% total mercury removal would be Toxecon™. This technology, which involves the installation of an activated carbon injection system and a fabric filter downstream of an existing particulate control device, is much more expensive and time-consuming to install than other mercury control technologies.

1.0 Introduction

This paper examines the costs and likelihood of success of achieving mandated mercury reductions at PPL's two Pennsylvania coal-fired electric generating plants -- Montour and Brunner Island (Martins Creek plant is not included as it is scheduled to be shut down in 2007) required by the U.S. EPA Clean Air Mercury Rule (CAMR) as announced in March 2005 and the proposed Pennsylvania DEP rulemaking that would require meeting control technology requirements and facility specific emission allowance caps by January 1, 2010 and 2015 without allowance trading. Pennsylvania has cited local deposition concerns as the reason for its proposed rule. Based on the determination made by ENVIRON in its companion study that local deposition is attributable to oxidized mercury and not elemental mercury, URS examined the costs and feasibility of achieving 90% reductions in oxidized mercury at PPL's Pennsylvania units with allowance trading to comply with CAMR and compared this alternative to Pennsylvania's proposal.

Achieving 90% reduction in oxidized mercury is generally achievable with wet scrubbers without the addition of any add-on control technology. Most of the large power plants in Pennsylvania are either equipped with a wet scrubber or will be equipped with wet scrubbers. Therefore, achieving the 90% reduction in oxidized mercury at these units is much more certain and much less costly than achieving reductions in total mercury necessary to remain within the expected allowance allocations for these units without allowance trading. This is particularly true in light of the variability of the mercury content of the coal used at these units and the confidence in achieving total mercury reductions with the application of mercury control technologies.

To go further and make reductions in total mercury necessary to remain within the expected allowance allocations for these units without allowance trading, it will be necessary to either convert elemental mercury to an oxidized form and then remove it with the wet scrubber or remove both the elemental and oxidized forms of mercury with a carbon adsorption system.

There is a lack of confidence as to the amount of total mercury reduction that can be achieved by such additional mercury control technologies. This uncertainty varies with the availability, type and duration of test data for each control technology. Most control technology experience is short term (30 days or less) and that is not enough time to determine balance-of-plant impacts and true operating and maintenance costs. Also, many emerging technologies that are claimed to be able to achieve substantial reductions have not been tested over sufficient periods and by independent third parties.

Even if a mercury control technology is tested for a long time and the confidence level in the mercury control efficiency is relatively high, the application of that mercury control technology to Brunner Island and Montour Units could result in a significantly different mercury reduction percentage. This is especially true if very high control efficiencies are required. URS believes that control efficiencies as high as 98% could be required to remain within the expected allowance allocations for these plants, depending on the mercury content of the coal. There is little experience of any mercury control technology operating on utility size coal-fired boilers achieving better than 90% total mercury reduction. Also, there is a lack of actual mercury emission reduction data obtained in long-term operation of Pennsylvania coal-fired boilers.

Mercury control technologies for U.S. coal-fired power plants are currently under development by a range of process developers. Control technology performance is generally specific to each power generation unit, and is impacted by the concentrations of other components of the coal, operating conditions in the boiler where the coal is fired, and the types of existing environmental controls used to clean up the flue gas produced from coal combustion. See Appendix A of this report for a discussion of coal firing to produce electric power, existing air pollution controls typically used on coal-fired power boilers, and mercury control technologies being developed for these applications.

DOE has been a leader in sponsoring mercury control demonstrations. However, their significant program has led to testing at only 28 coal-fired units, which represent only 2.3% of the 1,165 coal-fired units in operation in the U.S. See Appendix B (incorporated by reference) for a good summary of DOE's conclusions based on those demonstrations. As DOE notes, "there remain a number of critical technical and cost issues that need to be resolved through additional research before these technologies can be considered commercially available for all US coal and the different coal-fired power plant configurations in operation in the United States."[1] This conclusion is particularly true for the Pennsylvania power plants with wet scrubbers removing mostly oxidized mercury.

To meet the expected allocated mercury emission levels imposed by the Pennsylvania DEP regulation, the required mercury control efficiencies are in 95 to 96% range. The control technology that is the most promising (but with no commercial guarantee) to achieve such levels of reduction is an activated carbon injection (ACI) system based on carbon adsorption technology. In this process, activated carbon powder is injected into the flue gas duct where it adsorbs gas-phase mercury before being removed across a particulate control device. However, if the use of ACI technology results in the contamination of the fly ash or synthetic gypsum making either unusable for resale or beneficial applications, then landfills will need to be developed or mine reclamation utilized, typically at unacceptable economic penalty. To avoid any such contamination, a technology called Toxecon™ has been developed by EPRI. This technology, which involves the installation of an activated carbon injection system and a fabric filter downstream of an existing particulate control device, is much more expensive and requires a longer lead-time to install than other mercury control technologies.

In summary, since the DEP regulation does not allow for a cap-and-trade program it is required that the control technology must guarantee greater than 95% removal from the weighted average mercury content. The proposed DEP rule provides no flexibility, compared to CAMR, in terms of the ability to use interstate trading of mercury allowances to achieve compliance if there is a marginal reduction in the control efficiency or coal mercury were to average higher than expected in any given year long period. There is no demonstrated technology that can achieve such reduction levels and technologies that may potentially achieve such levels are very expensive to install. However, a 90% reduction in oxidized mercury with allowance trading to achieve some or all of the remaining reductions in total mercury required to achieve the expected

CAMR-based mercury budget allocation for PPL's Pennsylvania's units would be technologically feasible without severe economic penalty.

2.0 Description of PPL Pennsylvania Units

PPL has full ownership of seven coal-fired electric generating units located at three power stations in Pennsylvania. In these electric generating units, coal mined predominantly in Pennsylvania is finely ground and then burned in a boiler to produce steam at high pressure and temperature. This steam is used to drive multi-stage turbines attached to generators. The generators produce electric power, which is distributed to homes and businesses in the region. Table 1 lists the seven units, grouped by power station, and shows their power generation capacity. Note that the two small coal-fired units at the Martins Creek Station are planned to be retired in 2007, and so are not further discussed in this document.

Table 1. Coal-fired Electric Generating Units Owned or Co-owned by PPL in Pennsylvania

Power Station	Unit No.	Power Generation Capacity MW
Brunner Island	1	348
	2	404
	3	778
Montour	1	750
	2	750
Martins Creek	1	156
	2	156

The following subsections provide additional detail about these PPL Pennsylvania units that is relevant to mercury control regulation. The first subsection discusses the coal-fired by the units, while the second subsection describes the processes currently being used or planned for use on these units to control emissions to the atmosphere from firing coal to produce electricity.

This section and Section 3, which follows, provide information about the operation of coal-fired power plants, about existing air pollution control technologies on coal-fired plants, and about developing mercury control technologies. A number of technical terms and acronyms are used in this discussion. Appendix C of this report provides a glossary that defines these technical terms and acronyms. Also, Appendix A provides a more comprehensive discussion of these topics.

2.1 Coal Fired in PPL Pennsylvania Units

The coal fired in the PPL Pennsylvania units is primarily Eastern bituminous coal mined in Pennsylvania. The coal has a medium to high sulfur content, and a relatively high mercury content compared to other Eastern bituminous coals.

The amount of chlorine in coal impacts the percentage of mercury that is in the oxidized form as the flue gas enters the air pollution control equipment downstream of the boiler. Low-chlorine coals (less than 100 ppm chlorine in the coal), such as are typically found in the western United States, produce mostly elemental mercury, which is water insoluble and not readily removed in control devices such as wet scrubbers. Higher-chlorine coals tend to produce mostly oxidized mercury in the flue gas, which is water-soluble and can be removed at high efficiency by wet scrubbers.

The coals fired in the PPL Pennsylvania units are expected to contain more than 100 ppm of chlorine, and thus should produce mostly oxidized mercury in the flue gas. The percent oxidation of mercury in the flue gas has not been measured for all of the PPL Pennsylvania units, and may vary from day to day. For the Brunner Island units, which do not have an SCR, the percent oxidation of mercury in the flue gas at the scrubber inlet is expected to be in the range of 50% + /- to 70% +/-. For the Montour units, which have SCR, the scrubber inlet mercury oxidation is expected to be in the range of 80 to 90+%.

As described in the Introduction, coal is a very diverse resource, with properties that vary among coal types, regions of the country, mines and individual seams. Although some coal treatment processes exist, most coal is fired in steam electric plants just as it comes out of the ground.

In particular, the mercury content of coal can be quite variable. As an example, PPL collected mercury concentration data for samples of coal shipped to their Brunner Island and Montour Stations during one month in 2004. These analytical results are summarized in Table 2. The data show that the mercury content in these samples varied by a factor of greater than 12 when comparing the maximum to the minimum. Even comparing the maximum to the mean value, the factor is greater than two.

Table 2. Example Coal Mercury Data for Brunner Island and Montour Stations

Parameter	**Coal Mercury Content, lb/T Btu* heat content**	**Required Coal Mercury Control Percentage to Achieve EPA CAMR Phase II Limit (Montour Unit 2)**
Mean	21.8	96%
Maximum	52.7	>98%
Minimum	4.10	77%
Standard Deviation	14.9	97% (for mean + 1 Std Dev)

*lb/T Btu – pounds of mercury in a quantity of coal that produces one trillion (10^{12}) British Thermal Units [Btu] of energy for power production

Also shown in the table is the required control percentage of the coal mercury to achieve EPA's CAMR unit allocation for Phase II for one of the PPL Pennsylvania units, Montour Unit 2. The required percentage varies from nearly 96% removal for the mean coal mercury content to greater than 98% for the highest mercury content. The most cost effective mercury control technology which achieves 90% removal may not be able to achieve greater than 98% removal. Thus, with an inflexible mercury emission limit that does not allow interstate emissions allowance trading, the technology selection may be driven by the mercury content of the worst coal rather than the bulk of the coal or coal supply sources may become economically unusable.

We recognize that some latitude for coal variation is allowed by the fact that the proposed mercury emission limits must be met on a 12-month average basis rather than on an instantaneous basis. There are a number of factors that complicate this consideration, though. First, coal is brought into the PPL Pennsylvania units by train and by the truckload, from a number of mines and seams, mostly located within Pennsylvania. The coal mercury content in these many mines and seams is not "mapped" well enough to control when high-mercury-content coal is mined, stored and then fired weeks, months or even years later. Second, with current techniques for analyzing mercury concentrations in coal, it would be difficult to analyze coal as it is mined and delivered to the PPL Pennsylvania units and have those results available before that coal is fired if it is loaded directly into the unit, which is common practice. Thus, there is little capability to blend coal to reliably achieve mercury contents nearer the average.

For a strict mercury emissions limit that does not allow for interstate allowance trading, PPL may have to select a mercury control technology that can control to required levels for the worst possible annual average coal mercury content, rather than for a "likely" average. With the federal rule, PPL would have the flexibility of designing mercury controls for a realistic annual average coal mercury content, then purchasing allowances as needed in the event that a higher coal mercury content is encountered over, a 12-month period.

More data must be collected from Pennsylvania coal source deposits to be able to predict the coal mercury content in future years. These data will take time to collect and should be available before mercury control technology decisions are made. However, even with more data, there will remain a considerable uncertainty with respect to how representative samples may be of the entire coal deposit, and how to use sample results to predict the worst 12-months of coal supply. Again, a more flexible rule that allows for interstate trading of mercury allowances provides PPL the ability to respond to coal mercury content that is on the higher end of the predicted range.

2.2 Existing or Planned Air Emissions Control Technologies Used on PPL Pennsylvania Units

Other than grinding coal, or "washing" coal to remove some of the sulfur impurities, coal is typically burned or "fired" to produce steam and electricity just as it is mined from the ground. Coal contains impurities such as ash (unburned residue remaining after combustion), sulfur and nitrogen. This section describes the controls currently installed or planned for installation on PPL Pennsylvania units.

Fly Ash Control

Part of the ash drops out in the boiler and is collected there as bottom ash, but most is entrained in the combustion flue gases and fly ash that leaves the boiler. All coal-fired units in the U.S. have some sort of particulate control device to collect the fly ash particles that are entrained in the flue gas.

Many coal-fired units use electrostatic precipitator (ESP) technology to remove fly ash from the flue gas. ESPs use high-voltage electrical forces to attract fly ash particles onto metal collecting plates. The collecting plates are periodically vibrated ("rapped") to cause the collected fly ash to fall into hoppers below the ESP. From the hoppers, the ash is transported to storage silos. Fly ash is then either sold for beneficial use or sent for disposal. ESPs are used for particulate control in Brunner Island Units 2 and 3, and both Montour Units 1 and 2.

Brunner Island Unit 1 uses an alternate particulate control technology, a fabric filter. A fabric filter is a large chamber with a number of compartments, each filled with filter bags. The bags are made of woven fabrics. The flue gas must pass through these bags to exit the fabric filter. As the flue gas passes through the bag, the fly ash is collected on the bag surface. The bags are periodically cleaned by using reverse flue gas flow to dislodge the fly ash from the bags and it falls into hoppers below. From the hoppers the fly ash is handled the same as ash collected by ESPs.

Sulfur Dioxide Control

Sulfur in coal is oxidized during the combustion process to produce sulfur dioxide (SO_2), and often a small percentage of sulfur trioxide (SO_3). These are both present as gases rather than solids as the flue gas leaves the boiler, and can combine with moisture in the atmosphere to form acids. Depending on the age of the plant and the amount of sulfur in the coal, the plant may have a technology installed to capture sulfur dioxide in the flue gas.

Often this technology involves a wet scrubber. Scrubbers are discussed in greater detail below under Section 3.2, entitled "scrubber additives"; however, when a wet scrubber is used for sulfur dioxide control, it is typically installed downstream of the ESP or fabric filter, and generally consists of an open vessel where the flue gas flows upward and a water-based slurry is sprayed downward to contact the gas. In the process, the hot (~300°F) flue gas is cooled to about 120°F and saturated with moisture. This type of scrubber vessel is also called an absorber. In the scrubber, lime or finely ground limestone is added to the slurry to provide the alkalinity (basic species) to neutralize the acidic sulfur dioxide as it is scrubbed. This acid-base neutralization produces a calcium-based salt as a byproduct, either calcium sulfite hemihydrate, which is typically land filled or impounded in wet ponds for disposal, or gypsum (calcium sulfate dihydrate), which can be used to make wallboard such as is used in homes. The slurry being recirculated through the spray nozzles in the scrubber is a mixture of lime or limestone, calcium sulfite and/or gypsum.

None of the PPL Pennsylvania units currently are equipped with wet scrubbers for sulfur dioxide control. However, scrubber retrofits are underway, and by 2010 all three units at Brunner Island and both units at Montour will be scrubbed.

One of the significant co-benefits of wet scrubbers is the removal of oxidized mercury. As oxidized mercury is highly water soluble, wet scrubbers are a very effective technology for removing this form of mercury. Although there is limited data at present, testing has shown that scrubbers are capable of removing 90% of oxidized mercury based on inlet to outlet testing of the scrubber for oxidized mercury emissions.

Nitrogen Oxides Control

Coal also contains nitrogen as an impurity. When the coal is fired, this nitrogen can be converted to nitrogen oxides. Some of the nitrogen in the air used to combust the coal can also be converted to nitrogen oxides in the boiler. Nitrogen oxides in the atmosphere can react to form ozone and/or fine particulate matter. Consequently, many coal-fired units have technologies installed to control nitrogen oxide emissions. One common technology is selective catalytic reduction

(SCR). In SCR systems, catalysts are used to promote chemical reactions between nitrogen oxides in the flue gas and ammonia injected into the flue gas. Catalysts are materials that participate in chemical reactions and allow them to proceed more rapidly, but are not consumed in the reaction. In the catalytic reaction, ammonia is consumed and nitrogen oxides are chemically reduced to form nitrogen and water vapor. The SCR reactions proceed most rapidly at elevated flue gas temperatures (~700°F), so most SCRs are installed in the flue gas path upstream of the ESP (or fabric filter) or wet scrubber. Both of the units at Montour Station are currently equipped with SCR, but Brunner Island units are not. There are no current plans to retrofit SCR to the Brunner Island units.

Ramifications of the current and planned air emissions control technologies on current mercury capture and on the potential effectiveness of developing mercury control technologies on the PPL Pennsylvania units are discussed later in this report. Also, ESP, fabric filter, wet scrubber and SCR technologies are described in further detail in Appendix A.

3.0 Development Status and Performance Confidence Level of Mercury Control Technologies

This section discusses: (1) technologies for achieving 90% reduction of oxidized mercury and (2) mercury control technologies that might be considered for the PPL Pennsylvania units to make reductions in total mercury emissions beyond the 90% reductions in oxidized mercury.

3.1 Base Case of 90% Oxidized Mercury Control Technology

As noted in section 2.2, wet scrubbers are highly effective in removing oxidized mercury. In fact, even though the data is limited, this technology is considered state of the art for removing oxidized mercury and expected performance is 90% removal as measured across the scrubber.

None of the PPL Pennsylvania units currently are equipped with wet scrubbers for sulfur dioxide control. However, scrubber retrofits are underway, and by 2010 all three units at Brunner Island and both units at Montour will be scrubbed. A co-benefit of a wet scrubber, apart from removing sulfur dioxide, is to remove the oxidized form of mercury. Wet scrubbers are capable of capturing the water-soluble oxidized mercury in the flue gas, but remove little or no elemental mercury, which has low water solubility. Achieving 90% reduction in oxidized mercury is generally feasible with wet scrubbers without the addition of any add-on control technology. Most of the large power plants in Pennsylvania are either equipped with wet scrubber or will be equipped with wet scrubbers. Therefore, achieving the 90% reduction in oxidized mercury at these units is much more certain and much less costly. This is particularly true in light of the variability of the mercury content of the coal used at these units and the confidence in achieving total mercury reductions with the application of mercury control technologies.

The confidence level in removing 90% oxidized mercury with the wet scrubber is high however long-term test data are still unavailable. This confidence is certainly higher than most of the other mercury control technologies discussed in the next section for total mercury control. A number of full-scale plant measurements have shown that wet scrubbers installed for sulfur dioxide control can remove a high percentage of the water-soluble, oxidized mercury in a flue gas and typically remove little elemental mercury. Removal of oxidized mercury by wet scrubbers can be limited by a phenomenon called "re-emissions," which results in a portion of the scrubbed oxidized mercury being chemically reduced to elemental mercury in the scrubber liquor. Once reduced, the insoluble elemental mercury is released back into the flue gas. The re-emissions process is not completely understood at this time, but is believed to occur by reaction with dissolved sulfur dioxide in the scrubber liquor.

3.2 Total Mercury Control Technologies

This section discusses a range of mercury control technologies that might be considered for the PPL Pennsylvania units to make reductions in total mercury emissions beyond the 90% reductions in oxidized mercury expected to be achieved with scrubbers. For each candidate technology, a brief overview is provided of how the technology works, the expected control performance, the experience base, applicability to PPL Pennsylvania units, and uncertainties in applying these technologies to the units.

The candidate technologies considered include the following:

- Coal Pre-treatment;
- Chemical Addition;
- Combustion Modifications;
- SCR Retrofit;
- Activated Carbon Injection;
- Toxecon^{TM};
- Oxidation Catalysts; and
- Scrubber Additives.

These technologies are listed and discussed in order of the application point in the coal combustion and flue gas cleanup processes. The options range from pre-treating the coal before it is fired to a flue gas treatment just before the flue gas is released to the atmosphere.

Each of the technologies is discussed at an overview level below. More detailed information about each of these technologies, as well as background information about mercury chemistry in coal and coal flue gases, is also provided in Appendix A. The reader is encouraged to read Appendix A to gain a more detailed understanding of the information discussed below.

As mentioned above, add-on mercury control technologies are presented and discussed in order according to where they would be installed in the coal firing and flue gas cleanup processes. Each add-on technology is shown in the same order in Figure 1.

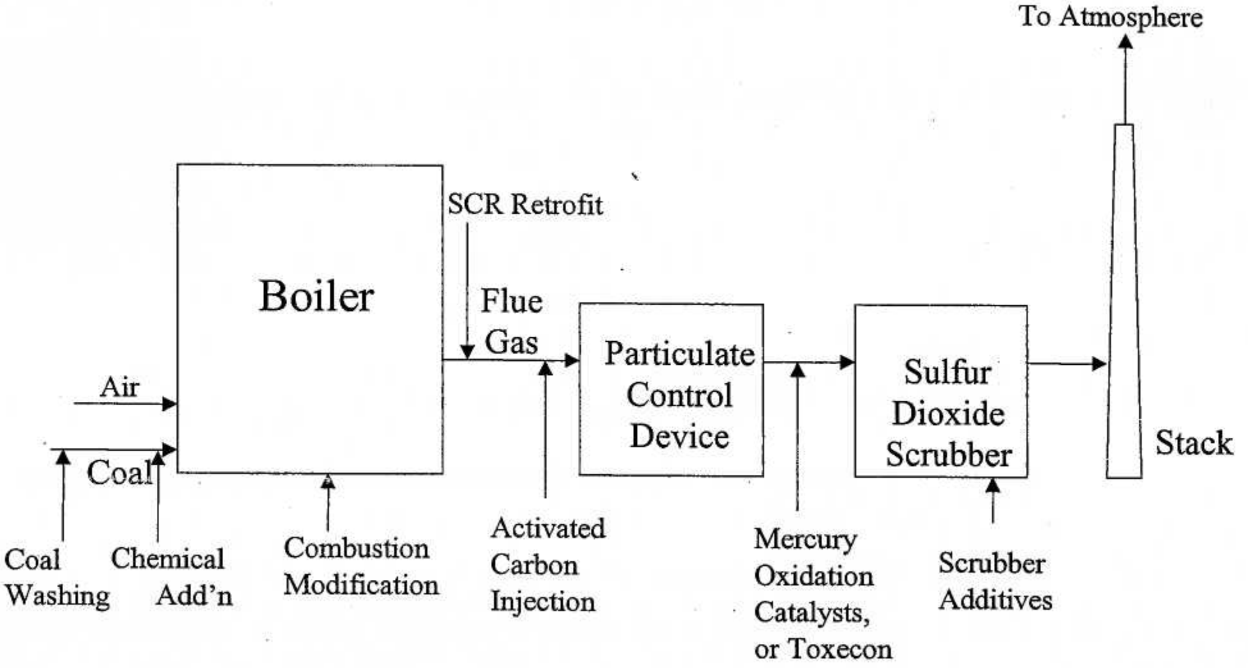

Figure 1. Schematic of Coal Firing and Flue Gas Processes Showing Locations of Potential Mercury Control Technologies

Coal Washing

There are a number of coal cleaning technologies available, some of which involve water washing the coal to remove sulfur species call pyrites (iron sulfides). Mercury occurs primarily in association with pyrites in bituminous coal, so coal washing can reduce the quantity of both sulfur and mercury in the coal fired. However, the cost of washed coal is greater than the cost of unwashed coal due to the cost associated with the additional processing steps and the loss of some coal in the high-sulfur-content reject stream. The amount of mercury that can be removed from a coal with washing can be quite variable, but is typically in the range of 20% to 40%. By reducing the mercury in the coal, this technology would reduce both the oxidized and elemental mercury emissions.

Chemical Addition

This technology is aimed at oxidizing elemental mercury so as to reduce total mercury emissions. This oxidized form of mercury in coal flue gases is water-soluble and can be removed in wet scrubbers, while the other predominant form, elemental mercury, is not. Halogen species such as chlorine are found in most coals, and are known to react with elemental mercury to produce the water-soluble oxidized form. Correspondingly, eastern coals with higher chlorine content produce mostly oxidized mercury in their flue gases, while western coals with low chlorine content, tend to produce mostly elemental mercury. One way to increase the amount of total mercury removed by wet scrubbers is to add halogens such as chlorine or bromine to the coal to increase the percentage of mercury in the flue gas that is oxidized. Halogen salts such as calcium chloride ($CaCl_2$) or calcium bromide ($CaBr_2$) can be added to the coal or injected as a liquid solution into the boiler furnace as a means of supplementing the coal chlorine content. Halogen injection tests have been conducted on approximately one dozen coal-fired units in the U.S., in short term tests of 30 days or less. No U.S. coal-fired unit currently injects halogens on a full-time basis as a mercury control technology.

Salts added with the coal or injected into the furnace decompose at furnace temperatures to form vapor-phase acids (hydrochloric acid [HCl] or hydrogen bromide [HBr]) in the flue gas. These vapor-phase halogen acids react with elemental mercury to produce oxidized mercury that can be removed by a downstream wet scrubber. Full-scale tests have been conducted on a number of coal-fired units that fire Powder River Basin coal, Texas lignite, and North Dakota lignite, for test durations of up to 30 days. The results have shown that injecting halogen salts in this manner can produce flue gas mercury oxidation percentages of 90% or greater.[2] However, no tests have been conducted in the U.S. on units that fire eastern bituminous coal. It remains to be demonstrated whether halogen injection with the coal or into the furnace would be effective at promoting higher mercury oxidation percentages than result just from the chlorine content of the bituminous coals.

Results have also shown that calcium bromide can be injected at lower concentrations of bromine than the amount of chlorine in calcium chloride required to produce equivalent oxidation percentages.[2] Most of the full-scale test results have shown that higher overall levels of mercury oxidation can be achieved with calcium bromide injection and that this reagent might be more cost effective than calcium chloride injection when the delivered costs of the salt solutions are considered. However, existing patents on the use of bromine to oxidize mercury may require royalty payments to the patent holder. Alstom is the only licensee in the U.S. that is authorized to commercialize this technology, under the trade name "KNX." Furthermore, the cost of the bulk reagent has increased dramatically over the past two years. Thus, there are a number of uncertainties associated the cost of calcium bromide injection.

Furthermore, the halogen acids added to the flue gas are scrubbed at high efficiency in wet scrubbers and form soluble salts that build to high concentrations in wet scrubber slurries. Chloride salts are known to produce severe pitting corrosion in metallic components unless impervious coatings are applied or high nickel content alloys are used. Bromine is typically not present in coal flue gases at significant concentrations, so the long-term effects of bromine injection on wet scrubber chemistry and wet scrubber materials of construction are not known. Even for calcium chloride injection, the injection of this salt can greatly increase the chloride content of the liquor circulating through the wet scrubber, and can cause extensive corrosion of metal components if they were not designed for such elevated chloride levels.

Combustion Modifications

This potential mercury control process can be implemented during the combustion process, as would the chemical injection described above, but the mercury capture mechanism would be different. While the chemical injection process is aimed at modifying the chemical form of the mercury to make it removable in a wet scrubber, the combustion modification process is aimed at modifying the fly ash to make it capable of physically adsorbing mercury. Adsorption is defined as a process where a gas, vapor or dissolved matter is assimilated by the surface of a solid or liquid. To change the fly ash properties, the combustion properties of the boiler are modified by changing the way the coal is burned in the furnace. This may include changing the ratio of coal to combustion air added to the boiler or changing the location of the fireball in the furnace by modifying the amount of fuel added at different locations in the boiler.

Most fly ash is composed of non-combustible minerals that are found in the coal. These minerals have little capacity to adsorb mercury. Boiler combustion modifications may be used to add unburned carbon to the fly ash. In some flue gases, unburned carbon has the capacity to adsorb mercury. The unburned carbon, including adsorbed mercury, is subsequently collected along with fly ash in the particulate control device.

It has long been observed that, for eastern bituminous coal-fired plants significant mercury control percentages can be achieved with fly ash having elevated unburned carbon levels. Recent test programs on a few plants that fire eastern bituminous coal have shown that it is possible to increase the unburned carbon content of the fly ash and optimize other flue gas variables to enhance mercury adsorption (and thus capture) with the fly ash. However, there is quite a bit of uncertainty associated with combustion modification as a compliance option. The effectiveness of this technology is expected to be very boiler specific. Results are presently available from only five full-scale test programs conducted by the two organizations, so it is difficult to project what might be achieved in the PPL Pennsylvania units, or other units in Pennsylvania.

SCR Retrofit

SCR technology was briefly described above in Section 2. SCR systems contain oxidation catalysts that can also promote oxidation of elemental mercury thus reducing total mercury emissions on units also equipped with wet scrubbers.

As mentioned above for Chemical Injection, oxidized mercury is water soluble and readily collected by wet scrubbers, while elemental mercury is insoluble and is not scrubbed at significant percentages. Eastern bituminous coals with high chloride content (greater than 100 ppm chloride in the coal) tend to produce mostly oxidized mercury in the flue gas. Measurements conducted by DOE and EPRI have shown that SCR systems installed on bituminous coal units equipped with SCR can promote further oxidation of mercury in the flue gas and greater capture of flue gas mercury in wet scrubbers. Thus, retrofitting an SCR system for control of nitrogen oxides on units that fire eastern bituminous coal and that have wet scrubbers for SO_2 control can have an added benefit to mercury capture.

However, it appears that catalyst conditions that favor mercury oxidation also favor SO_2 to SO_3 oxidation – an undesirable phenomenon that has been associated with colored acid plumes forming in the atmosphere downstream from a unit's stack. In fact, PPL has been looking at ways to minimize SO_3 formation and intends to investigate low SO_2 oxidation catalyst formulations, to help avoid problems associated with high SO_3 concentrations in flue gas. These low SO_2 conversion catalysts may be less effective at oxidizing mercury. This raises some question as to how much benefit to mercury oxidation and capture will be realized in future SCR retrofits.

Also, it is not clear that an SCR unit combined with an ESP for particulate control and a wet scrubber for sulfur dioxide control will achieve high mercury removal efficiencies of 90% or greater. As an example, Consol Energy measured mercury removal from the incoming coal to the stack flue gas on six power plant units fired with eastern, high-sulfur bituminous coal. All six units were equipped with an SCR, ESP and wet FGD system. These measurements showed that the six units averaged 86% mercury capture, with a range from 84% to 89% (one unit's mercury removal value was adjusted upwards from 72% to 84% to account for flue gas bypass around the FGD absorber).[3]

Activated Carbon Injection (ACI)

ACI is implemented by pneumatically injecting a fine powder of activated carbon into the flue gas duct upstream of the particulate device. Activated carbon is made from coal or lignite that is processed with heat and steam to produce a highly porous material that has great capacity for adsorption. As described above for unburned carbon in a boiler, mercury in the flue gas can adsorb onto the highly porous carbon particles, and be collected along with the carbon in the unit's particulate control device.

ACI is the most demonstrated of the add-on mercury control technologies considered here. Short-term (30-day or less) ACI tests have been conducted on dozens of coal-fired units in the U.S. However, the performance of ACI for mercury control can be very site specific. Factors such as flue gas residence time in ductwork, particulate control device type and size, flue gas temperature, and concentrations of other species in the flue gas affect the performance of ACI and make it difficult to use full-scale performance data from one site to predict performance at another.

Lower flue gas HCl concentration, higher temperature (>300°F), and the presence of sulfur trioxide (SO_3) in the flue gas tend to affect adversely ACI performance. The only factor favorable to ACI performance at PPL's Pennsylvania units is the bituminous coal that has significant chlorine content (>100 ppm), which produces HCl in the flue gas at concentrations that should support good ACI performance. All other factors are negative. The flue gas temperatures in the PPL Pennsylvania units are typically greater than 300°F upstream of the particulate control devices, which could be disadvantageous for ACI performance. Also, the medium- to high-sulfur coals fired in these units contain SO_3, which can limit the effectiveness of ACI due to competition between mercury and SO_3 for adsorption sites on the carbon. Note that brominated carbons do not address the adverse effects of SO_3 in the flue gas, only the effects of low HCl concentrations.

The type of particulate control device installed on a unit can greatly impact the effectiveness of ACI. ACI is most effective with a fabric filter, where the flue gas passes through filter bags that collect the fly ash and allow the flue gas to pass through. These filter bags serve as a fixed bed for the injected carbon, enabling intimate flue gas/carbon contact. ESPs are less effective than fabric filters as a gas contactor and typically require 4-10 times more added carbon to achieve the same levels of mercury removal as a fabric filter.

One disadvantage of using ACI for mercury control is that the carbon in the fly ash adversely affects the air entrainment capabilities of concretes made using that fly ash to replace some of the cement. (Air entrainment affects the freeze/thaw resistance of the concrete). It is generally assumed that if ACI is employed, the resulting fly ash will not be useable for cement/concrete applications. However, it may still be suitable for engineered fill applications as long as fly ash loss-on-ignition (LOI) specifications are not exceeded. There are alternate implementations of ACI that can preserve the integrity of the fly ash and its sale for concrete applications. One alternate process, Toxecon^{TM}, is described later in this section.

Another disadvantage of using ACI for mercury control ahead of an ESP and wet scrubber is if the activated carbon exits the ESP and contaminates the gypsum produced by the wet scrubber. The resulting gypsum will not be useable for producing wallboard or for similar applications due to flammability concerns.

Mercury Oxidation Catalysts

Catalysts are materials that participate in chemical reactions and allow them to proceed more rapidly, but are not consumed in the reaction. Catalysts have been identified that promote the oxidation of elemental mercury in flue gases from low-chlorine coals such as Powder River Basin coal. These oxidation catalysts are typically inserted into the flue gas ducts as "honeycomb" type structures with many small passages through which the flue gas flows. This provides a large surface area to which the catalyst materials are applied and on which the oxidation reactions can take place.

This increases the percentage of the mercury in the flue gas that is in the water-soluble oxidized form, and enhances mercury capture by a downstream wet scrubber. However, catalytic oxidation technology has to date only been tested at pilot scale. Furthermore, pilot testing has only recently begun on a unit that fires bituminous coal, such as is fired in the PPL Pennsylvania units. It remains to be seen how effective the catalyst will be over a long period (>1 year) for promoting high mercury oxidation percentages in flue gas from bituminous coal.

Furthermore, there are two caveats about using low-temperature catalysts for achieving high mercury capture percentages. One is that the overall mercury capture percentage may be limited by the net removal of oxidized mercury by the downstream wet scrubber, due to the effects of mercury re-emissions as described below. The second is that oxidation catalysts begin service at their maximum mercury oxidation activity, and then lose activity over time due to poisoning effects of other species in the flue gas. With time, the oxidation of elemental mercury across these catalysts tends to decay. To maintain high oxidation percentages over time, either a large excess of catalyst, frequent catalyst replacement, or frequent catalyst regeneration may be required.

Powerspan has licensed an alternate technology that uses ultraviolet light to oxidize selectively mercury in flue gas. They have recently announced a pilot-scale evaluation of the technology, which they call Photochemical Oxidation or PCO™, that will be conducted on an Ameren UE unit in Missouri that fires Powder River Basin coal.[4] Until that pilot-scale testing is conducted, beginning later in 2006, there is no basis for predicting the effectiveness or cost of this technology on wet scrubbed units. Even those results will have limited applicability to the PPL Pennsylvania units and other similar units in Pennsylvania, which fire bituminous coal.

Scrubber Additives

As described earlier in this section, wet scrubbers are capable of capturing the water-soluble oxidized mercury in the flue gas, but remove little or no elemental mercury. However some of the oxidized mercury captured by the wet scrubber can be re-emitted as elemental mercury. This phenomenon called "re-emission," is where oxidized mercury absorbed in the scrubber liquor is chemically converted back to the elemental form. Since the elemental mercury formed is not water soluble, it is released back into the scrubber outlet flue gas. Evidence of re-emissions is seen when the elemental mercury concentration in the flue gas at the outlet of a wet scrubber is higher than the inlet elemental mercury concentration.

The chemistry of mercury re-emissions in wet scrubbers is not completely understood at this time. While it is believed that the chemical reactions leading to re-emissions have been identified, the relative rates of various competing reactions are not yet known. In the future, it may be possible to model mercury reactions in wet scrubber liquors and adjust scrubber operating conditions to eliminate or at least limit re-emissions. In the interim, an approach identified for controlling re-emissions is to use scrubber additives.

Additives generally work by rapidly precipitating oxidized mercury from the scrubber liquor as a solid salt, so it will not react with other liquid-phase species, such as absorbed sulfur dioxide, and be converted back to the elemental form. Scrubber additives have been used in Europe to prevent re-emissions from wet scrubber systems installed on municipal waste burning power plants, and have reportedly been used for this purpose in some coal-fired plants. Limited testing of wet scrubber additives have been conducted in the U.S., by URS and by Babcock and Wilcox.[5,6] Further testing of the effectiveness of scrubber additives in preventing re-emissions from the wet scrubbers on U.S. coal-fired units is required before this technology can be applied with confidence.

Toxecon™

EPRI has developed a patented technology that addresses several of the shortcomings of conventional ACI for plants currently equipped with an ESP for particulate control. In this process, called Toxecon™, a very compact fabric filter is installed in the flue gas path downstream of an existing ESP. Activated carbon is injected into the flue gas just upstream of this compact fabric filter. The fabric filter serves as a more effective contact device between the activated carbon and the flue gas, so less activated carbon is needed and/or higher mercury removal percentages can be achieved. Furthermore, the Toxecon™ process allows the fly ash to be collected in the existing ESP while the carbon and a very small amount of fine fly ash is collected in the downstream fabric filter. This allows the plant to continue fly ash sales and/or reuse without being impacted by carbon in the ash.

However, the Toxecon™ process has not been tested in flue gas from a medium- to high-sulfur bituminous coal. Consequently, there is not a good technical basis for projecting the performance or cost of a Toxecon™ installation on the PPL Pennsylvania units, or other similar Pennsylvania units.

3.3 Control Technology Summary

This section has included extensive discussions of mercury control technologies (including some that do not appear to be well suited) that could potentially be applied to the PPL Pennsylvania units, and other similar Pennsylvania units, to achieve reductions in total mercury beyond the reductions in oxidized mercury achieved through scrubbers. Table 3 provides a summary of this information, as well as listing URS' projections of the maximum effectiveness of each technology at controlling the emission of the mercury in the incoming coal, and our confidence in those performance projections.

Table 3. Summary of Mercury Control Technologies Considered for PPL Pennsylvania Units

Technology	Maximum Total Mercury Removal	Development Status	URS Confidence in Performance Projections
Coal Washing	20-40%	Commonly practiced to lower coal S content, limited data on Hg removal	Low (results are very coal specific)
Chemical Injection/KNX (with wet scrubber)	~80-90%	~12 short-term full-scale trials	Low (questions about balance of plant effects, wet scrubber removal of oxidized mercury, and lack of data for bituminous coal)
Combustion Modification	Unknown	Short-term, full-scale trials on ~10 boilers	Low (results are very site specific)
SCR Retrofit (with wet scrubber)	85-90%	Mercury oxidation measurements have been made at ~12 full-scale SCR retrofits on bituminous coal	Moderate (impacts of low SO_2 to SO_3 conversion catalysts have not been fully documented)
ACI	50-90% (plus downstream removal by wet scrubber)	Several dozen full-scale trials	Low (few data for medium- to high-sulfur bituminous coal)
Toxecon™	50-90% (plus downstream removal by wet scrubber)	Demonstrated on low-sulfur Eastern bituminous coal, demo in progress for Power River Basin coal.	Low (no data for medium- to high-sulfur bituminous coal)
Oxidation Catalyst (with wet scrubber)	~80-90%	Pilot tests only	Low (no data for medium- to high-sulfur bituminous coal)
Wet Scrubber Additive	See note under "URS Confidence"	Short term pilot and full-scale tests in U.S. (none on PRB coal or wet particulate scrubbers)	Low (limited results available for U.S. coals and wet scrubbers) NOTE - Not a standalone technology, used to minimize re-emissions of elemental mercury in scrubber inlet gas

3.4 Candidate Control Technology Cost Estimates

The information presented in Section 2 and earlier in this section was used to develop cost estimates for applying candidate mercury control technologies to the PPL Pennsylvania units. The estimates were focused on the later control levels (2018 for EPA's CAMR and 2015 for the proposed DEP regulation). The costs identified are those costs that are beyond the cost of the technology the plants will be installing anyway even without any mercury control requirement. At Montour, scrubbers and SCRs would be installed at both units anyway and scrubbers would be installed at Brunner Island on all three units anyway.

To meet the allocated mercury emission allowances under the EPA regulation, calculations were made to determine mercury control technology efficiency for each unit at Brunner Island and Montour Stations operating at 80% capacity factor. As shown in Table 4A, 88 to 90% removal of the mercury in the coal would be required with the average mercury content in coal to achieve the EPA CAMR mercury emission allocations for 2010 for these units.

Table 4A. Estimated Control Efficiency for meeting Expected Emission Allowances for the 2010 requirements

PPL Generation Power Station Electric Generating Unit	Rated Heat Input (million Btu/hr)	Coal Mercury (lb/trillion Btu)	Mercury in fuel at 80% Capacity Factor (lb)	Mercury Emission Allowances for the year 2010		
				EPA Allocated Mercury Emission Allowance (lb)	Allocated Emission Allowance with 3% holdback (lb)	Mercury Control Efficiency to meet Allocation (%)
Montour Unit 1	7239	21.8	1106	138	121	88
Montour Unit 2	7239	21.8	1106	131	121	88
Brunner Island Unit 1	3314	21.8	506	50	48	90
Brunner Island Unit 2	3825	21.8	584	62	56	89
Brunner Island Unit 3	7239	21.8	1106	123	120	88

As shown in Table 4B, 95 to 96% removal of the mercury in the coal would be required with the average mercury content in coal to achieve the EPA CAMR mercury emission allocations for 2015 for these units.

Table 4B. Estimated Control Efficiency for meeting Expected Emission Allowances for the 2015 requirements

PPL Generation Power Station Electric Generating Unit	Rated Heat Input (million Btu/hr)	Coal Mercury (lb/trillion Btu)	Mercury in fuel at 80% Capacity Factor (lb)	Mercury Emission Allowances for the year 2015		
				EPA Allocated Mercury Emission Allowance (lb)	Allocated Emission Allowance with 3% holdback (lb)	Mercury Control Efficiency to meet Allocation (%)
Montour Unit 1	7239	21.8	1106	54	53	95
Montour Unit 2	7239	21.8	1106	52	50	96
Brunner Island Unit 1	3314	21.8	506	20	19	96
Brunner Island Unit 2	3825	21.8	584	24	24	96
Brunner Island Unit 3	7239	21.8	1106	49	47	96

This 95^{+}% removal includes mercury removal already achieved on these units with the existing or planned air emissions controls. For CAMR compliance, technologies that may be capable of achieving even the 90% overall mercury capture level could be considered, as the possibility exists for interstate trading of allowances in the event that a technology falls somewhat short in control efficiency. For compliance with the proposed DEP regulation of meeting the similar allocated mercury emission allowance without cap-and-trade program, only technologies with a high probability of achieving 95% or greater overall mercury capture must be considered.

Approach

The procedure for developing these cost estimates was as follows. First, a capital cost was estimated for each candidate technology. The capital costs were estimated based on cost information from other installations or from other more detailed estimates. The costs were estimated as a constant number of capital dollars per kilowatt of unit capacity, in 2005/2006 dollars. No attempt was made to survey the PPL Pennsylvania units to evaluate the difficulty of retrofit at that site, or to develop site-specific or unit-specific cost estimates. Thus, these costs estimates should be considered "generic." An exception is the capital costs for adding SCR to the Brunner Island units. For these estimates, PPL in-house engineering estimates were used.

Next, technology performance estimates were made, and these estimates were used to predict variable operating and maintenance (O&M) costs for each technology. There are a number of caveats that must be considered before presenting the results of this effort. First, the technology performance and variable O&M estimates assume that data from other units can be used to reasonably estimate performance on a PPL Pennsylvania unit. However, many mercury control technologies are site specific in performance, so data from another unit could either over-predict or under-predict performance at Brunner Island or Montour. Also, the variable O&M costs are based on current retail pricing for these materials, and estimates for the current price of delivering these materials to Brunner Island or Montour – no attempt has been made to escalate these costs into the time period of 2010 to 2015.

The variable O&M costs address only consumables such as reagents and associated costs. No attempt has been made to estimate the cost of operator time to run the new equipment, or maintenance hours or materials required to maintain the new equipment in proper operating condition. However, the O&M estimate was adjusted to account for the added pressure drop of the retrofitted fabric filter for the Toxecon^{TM} cases. Also, for the ACI cases, the potential loss of fly ash byproduct revenues due to the addition of carbon, and the corresponding fly ash disposal costs were evaluated.

In summary, these estimates could under-predict the cost of applying the candidate technologies to PPL Pennsylvania units, and other similar units in Pennsylvania. However, they can be considered "conservatively low" (i.e., no attempt to overstate future compliance costs) and are useful for comparing control technologies, such as those considered here, that have a diverse range of capital and variable O&M costs.

Results

As described above, the mercury control technologies costs are considered for compliance with the Pennsylvania DEP proposed regulation for the control technology requirements and allocated mercury emission allowances for the year 2015. With a wet scrubber on all units, it is possible to remove 90% oxidized mercury on each unit without the addition of any add-on control technology. With the addition of SCR and/or other oxidization technologies, such as use of chemical agents or oxidation catalyst, some elemental mercury will be converted to oxidized form and removed with the wet scrubber. Therefore, with the use of SCR and/or other oxidation technologies, it is possible to get to 90% total mercury removal. However, as presented above in Table 4B, to remain within each unit's expected mercury allowance allocation based on EPA's CAMR budget, the required mercury control efficiencies are in 95 to 96% range, or even as much as 98%. The only technology that has a chance of getting to better than 95% total mercury removal would be to add activated carbon injection or Toxecon^{TM} as a polishing unit towards the tail end. The success of this approach remains very uncertain. Since the proposed DEP regulation does not allow trading, it is required that the control technology must guarantee better than 95% removal with the average mercury content. The evaluation of compliance for meeting the allocated mercury emission allowance or higher coal mercury content provides no flexibility in the DEP proposed rule compared to CAMR in terms of the ability to use interstate trading of mercury allowances to achieve compliance if there is a marginal reduction in the control efficiency or coal mercury were to average higher than expected in any given year long period.

The results of these cost analyses are summarized in Tables 5(a), 5(b), and 5(c) for Montour, and 6(a), 6(b) and 6(c), for Brunner Island. The results in the tables can be compared to show how the number of technology options decreases and the cost of compliance increases as the control requirements shift from (a) 90% reduction in oxidized mercury, to (b) 90% reduction in total mercury, to (c) CAMR cap without trading.

Table 5(a). Control Technology Compliance Cost Estimates for 90% Oxidized Mercury Control – Montour Station Units

Unit	Average Coal Hg (lb/Tbtu)	Annual Hg in Coal (lb/yr)	Percent Removal of Oxidized	Technology/Confidence Level	Capital Estimate ($1000)	Annual Variable O&M Cost ($1000)
Montour 1	21.8	1106	90	Wet Scrubber/High	N.A.	N.A.
Montour 2	21.8	1106	90	Wet Scrubber/High	N.A.	N.A.

Table 5(b). Control Technology Compliance Cost Estimates for 90% Total Mercury Control – Montour Station Units

Unit	Average Coal Hg (lb/Tbtu)	Annual Hg in Coal (lb/yr)	Percent Removal of total Hg in Coal (%)	Technology/Confidence Level	Capital Estimate ($1000)	Annual Variable O&M Cost ($1000)
Montour 1	21.8	1106	72	SCR+Wet Scrubber /Moderate **	N.A.	N.A.
Montour 2	21.8	1106	72	SCR+Wet Scrubber /Moderate**	N.A.	N.A.
Montour 1	21.8	1106	90	Chemical addition + FGD additive/Low	$3,000	$1,000
	21.8	1106	90	Combustion Modification + FGD additive/Low	$1,600	$5,750*
	21.8	1106	90	Oxidation Catalyst + FGD additive/Low	$3,000	$3,500
Montour 2	21.8	1106	90	Chemical addition + FGD additive/Low	$3,000	$1,100
	21.8	1106	90	Combustion Modification + FGD additive/Low	$1,600	$5,750*
	21.8	1106	90	Oxidation Catalyst + FGD additive/Low	$3,000	$3,500

*includes $4,500,000 for increased unburned carbon content results in loss of fly ash sales and 1% additional coal consumption

** SCR + wet scrubber is shown, however as expected performance is only 72% it is does not meet the 90% removal requirement.

Note: ACI is not included in this table as the cost has been determined to be unacceptable due to contamination of the fly ash and gypsum. The costs associated with contamination are projected at $5,200,000 per year per unit.

Table 5(c). Control Technology Compliance Cost Estimates for 95$^+$% Total Mercury Control – Montour Station Units (expected to meet cap without trading)

Unit	Average Coal Hg (lb/Tbtu)	Annual Hg in Coal (lb/yr)	Percent Removal of total Hg in Coal (%)	Technology/Confidence Level	Capital Estimate ($1000)	Annual Variable O&M Cost ($1000)
Montour 1	21.8	1106	95$^+$	Toxecon^{TM}/Low	$75,000	$2,300
Montour 2	21.8	1106	95$^+$	Toxecon^{TM}/Low	$75,000	$2,300

Table 6(a). Control Technology Compliance Cost Estimates for 90% Oxidized Mercury Control – Brunner Island Station Units

Unit	Average Coal Hg (lb/Tbtu)	Annual Hg in Coal (lb/yr)	Percent Removal of Oxidized	Technology/Confidence Level	Capital Estimate ($1000)	Annual Variable O&M Cost ($1000)
BI Unit 1	21.8	506	90	Wet Scrubber/High	N.A.	N.A.
BI Unit 2	21.8	584	90	Wet Scrubber / High	N.A.	N.A.
BI Unit 3	21.8	1106	90	Wet Scrubber / High	N.A.	N.A.

Table 6(b). Control Technology Compliance Cost Estimates for 90% Total Mercury Control – Brunner Island Station Units

Unit	Average Coal Hg (lb/Tbtu)	Annual Hg in Coal (lb/yr)	Percent Removal of total Hg in Coal (%)	Technology/Confidence Level	Capital Estimate ($1000)	Annual Variable O&M Cost ($1000)
BI Unit 1	21.8	506	65	Wet Scrubber+FF / Moderate(1)	N.A.	N.A.
BI Unit 2	21.8	584	40	Wet Scrubber+ESP / Moderate(1)	N.A.	N.A.
BI Unit 3	21.8	1106	40	Wet Scrubber+ESP / Moderate(1)	N.A.	N.A.
BI Unit 1	21.8	506	90	Chemical addition + FGD additive/Low	$1,400	$670
	21.8	506	90	Combustion Modification + FGD additive/Low	$1,200	$1,970*
	21.8	506	90	Oxidation Catalyst + FGD additive/Low	$1,400	$1,800
BI Unit 2	21.8	584	90	Chemical addition + FGD additive/Low	$1,600	$980
	21.8	584	90	Combustion Modification + FGD additive/Low	$1,300	$2,190**
	21.8	584	90	Oxidation Catalyst + FGD additive/Low	$1,600	$2,500
BI Unit 3	21.8	1106	90	Chemical addition + FGD additive/Low	$3,100	$1,900
	21.8	1106	90	Combustion Modification + FGD additive/Low	$1,600	$4,070***
	21.8	1106	90	Oxidation Catalyst + FGD additive/Low	$3,100	$4,400

(1) -These technologies are shown as base technologies but are only expected to achieve the performance noted and do not meet the 90% removal requirement.

*includes $1,700,000 for increased unburned carbon content results in loss of fly ash reuse sales. Since fly ash LOI is already at 9 to 11.5% for this unit, this technology may be ineffective.

**includes $1,900,000 if increased unburned carbon content results in loss of fly ash reuse sales. Since fly ash LOI is already at 9 to 11.5% for this unit, this technology may be ineffective.

*** includes $3,600,000 if increased unburned carbon content results in loss of fly ash reuse sales. Since fly ash LOI is already at 9 to 11.5% for this unit, this technology may be ineffective.

Note: ACI is not included in this table as the cost has been determined to be unacceptable due to contamination of the fly ash and gypsum. The costs associated with contamination are projected at $12,600,000 per year for units 1&2 combined and $12,600,000 for unit 3.

Table 6(c). Control Technology Compliance Cost Estimates for 95$^+$% Total Mercury Control – Brunner Island Station Units (expected to meet cap without trading)

Unit	Average Coal Hg (lb/Tbtu)	Annual Hg in Coal (lb/yr)	Percent Removal of total Hg in Coal (%)	Technology/Confidence Level	Capital Estimate ($1000)	Annual Variable O&M Cost ($1000)
BI Unit 1	21.8	506	95$^+$	Toxecon™/Low	$40,000	$1,600
BI Unit 2	21.8	584	95$^+$	Toxecon™/Low	$40,000	$1,600
BI Unit 3	21.8	1106	95$^+$	Toxecon™/Low	$78,000	$2,800

As mentioned earlier, the costs presented in the above tables are those costs that are beyond the cost of the technology the plants will be installing anyway even without any mercury control requirement. Tables 5(a) and 6(a) show that a wet scrubber on all PPL units will achieve a 90% reduction in oxidized mercury emissions at each unit.

Tables 5(b) and 6(b) show the technologies and confidence level and costs for achieving a 90% reduction in total mercury. With the addition of SCR and/or other oxidization technologies, such as use of chemical agents or low-temperature oxidation catalysts, some elemental mercury will be converted to an oxidized form and subsequently removed with the wet scrubber. Thus for a unit configured with an add-on oxidation technologies, with an assumed 100% conversion of elemental to oxidized mercury, and a wet scrubber capable of removing 90% of the oxidized mercury in the gas, it would be possible to achieve a maximum of 90% total mercury removal. However, this level of conversion has not yet been demonstrated but our confidence is higher with the addition of SCR to other oxidization technologies. In fact, these technologies are more likely to have oxidation effectiveness ranging from 35 to 90+%. These are highly dependent on coal, boiler design and operation and other plant parameters. Here, assuming the same scrubber efficiency for removing oxidized mercury in both cases, the overall result of converting 100% elemental to oxidized mercury would result in higher emission of oxidized mercury but a net reduction in total mercury emission.

Tables 5(c) and 6(c) 8 show a substantial increase in capital investment to go from 90% total mercury capture using oxidation or combustion modification technologies to the 95+% control with Toxecon™ technology that would be required under the proposed Pennsylvania DEP regulation where interstate trading of allowances is not allowed.

4.0 Schedule Considerations

As is evident from the discussion above, mercury reduction technologies are not yet at the point that PPL can be confident they can achieve the levels of reduction required without trading or the proposed Pennsylvania rules..

Control technology development is being addressed by ongoing research efforts co-funded by the U.S. DOE and by private industry. DOE has sponsored four rounds of test programs (Phase I, Phase II-1, Phase II-2, and Phase III), which have made progress in the development of mercury control technology for U.S. coal-fired power plants. Phase I began in 2001, and Phase III projects were just selected for award in February 2006. Several Phase III projects are still under negotiation and will likely continue through mid-2009. Although these projects have supported the development of many new technologies, such as halogen-treated activated carbons that are more effective on low chlorine-content PRB coals, they have typically provided for only 30 days of continuous operation of the technology tested. Longer-term testing will be required to determine the true mercury control capabilities of these technologies on an annual basis, and to determine balance-of-plant impacts as well as true costs for applying the technologies.

Furthermore, most of the research supported by DOE has been focused on the coals that have been presumed to be more difficult for capture, such as low chloride western coals and lignites. Relatively little of this research has been focused on medium- to high-sulfur coals such as are mined and used for power production in Pennsylvania. Consequently, little is known about how to increase mercury capture beyond that realized through the co-benefits of ESPs or fabric filters, wet scrubbers, and perhaps SCR. As an example, only recently have there been full-scale data from power plants firing medium- to high-sulfur coal that show relatively poor mercury removal due to the competing effects of SO_3 in flue gas. Developments in activated carbon technology, such as bromine addition, do not address SO_3 effects.

DOE's Clean Coal Power Initiative program provides an opportunity to extend short-term results to multi-year, full-scale demonstrations of a select number of promising technologies. One such demonstration, of the Toxecon^{TM} process, is currently underway at a Wisconsin Electric plant that fires PRB coal. This project was funded as part of Round 1 of DOE's Clean Coal Power Initiative, announced in January 2003, and has just begun operation in early 2006. It is expected that additional mercury control demonstrations will be included as part of Round 3, for which the timing has yet to be announced. Assuming Round 3 is completed midway during Phase III of the short-term DOE projects, this would put proposals due sometime in 2007 or 2008, with award 6 months to a year later. If the timeline for Round 3 projects is similar to that of the Wisconsin Electric Round 1 project, it would be sometime in 2011 before such projects begin commercial operations, and sometime in 2014 before a multi-year demonstration is completed.

Using the chemical injection process as an example of an add-on mercury control that might be applicable to a Brunner Island unit, it would take a minimum of two years to go through a cycle of technology selection, environmental permitting, development of a specification, requests for proposals, proposal evaluation, negotiation with a successful bidder, process and detailed design, equipment procurement, construction, commissioning and startup. For a more complex project such as adding on a polishing Toxecon^{TM} retrofit at Montour, where additional land area may be required, a minimum of three to four years after selection of the technology is more likely.

Thus, to allow completion of expected future Clean Coal Power Initiative demonstrations of mercury control technologies and base technology decisions for high-efficiency mercury controls on results from these demonstrations, it would be somewhere in the time period of 2016 to 2017 before these new control systems would come on line. This timing would also allow opportunity for coal mercury content uncertainties to be better resolved. This timeline fits well with the timing of Phase II in EPA's CAMR.

However, the proposed Pennsylvania rule would require meeting allocated mercury allowance by January 1, 2010 and 2015 without allowance of trading and would thus necessitate a much earlier technology decision. The decision date would put PPL in an extremely difficult, if not impossible situation. Based on current technical knowledge, a Toxecon^{TM} retrofit as a polishing unit with the presumptive control technologies appears to be the only technology that could provide the level of mercury reduction required to meet the mercury emissions allowance for the PPL Pennsylvania units.

As discussed above, such a technology retrofit would require a minimum of three to four years after selection of the technology for installation. Three years from now would already be mid-2009 and four years would be mid-2010. Such a decision also would be extremely expensive and deprive PPL of the opportunity to explore the add-on technologies such as chemical injection or scrubber additives. There are also real concerns about the availability of labor to design, manufacture, purchase, and install Toxecon^{TM} retrofits at the Brunner Island and Montour units. Furthermore, there are additional peripheral changes at the plant that will add to these labor demands in retrofitting this technology. Some of those changes could include significant structural modifications and extended ductwork to address location of the additional dust collector, and fan modifications to address the increased pressure drop from the Toxecon^{TM} unit. Under these circumstances, the minimum three to four year lead-time following a technology decision may be substantially underestimated. Much more detailed analysis needs to be done to fully understand the impacts of proceeding with this technology, and addressing these changes will likely result in a several fold increase in the total cost of the Toxecon^{TM} retrofit at Brunner Island and Montour units. In short, such a commitment in 2006/2007 is impractical and essentially infeasible.

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Appendix A – Background: The Steam-Electric Generation Process and Mercury Emissions

In coal-fired steam-electric generating units, coal mined from the ground is finely ground and then burned in a vessel called a boiler to produce steam at high pressure and temperature. This steam is used to drive multi-stage turbines attached to generators. The generators produce electric power, which is distributed to homes and businesses in the region.

Other than grinding it to produce a fine powder, and sometimes washing it to remove a portion of the sulfur impurities, coal is typically burned or "fired" to produce steam and electricity just as it is mined from the ground. This coal contains impurities such as ash (unburned residue remaining after combustion), sulfur, and mercury. Part of the ash drops out in the boiler and is collected there, but most is entrained in the combustion flue gases that leave the boiler. All coal-fired units in the U.S. have some sort of particulate control device to collect the fine "fly ash" particles that are entrained in the flue gas.

Fly Ash Control

Many coal-fired units use electrostatic precipitator (ESP) technology to remove fly ash from the flue gas. ESPs use high-voltage electrical forces to push fly ash particles onto metal collecting plates. Periodically, these plates are "rapped" to shake the collected ash loose, and it falls to hoppers in the bottom of the ESP from which it is transported elsewhere for reuse or disposal.

Some units instead have fabric filters for particulate control. Fabric filters consist of vessels with a number of compartments, each filled with filter bags. The bags can be made of either woven or felt type fabrics. The flue gas must pass through these bags to exit the fabric filter. As the flue gas passes through the bag, the fly ash is collected on the bag surface. The bags are periodically cleaned by using compressed air or reverse flue gas flow to knock the ash loose from the bags into hoppers below.

A third type of particulate control technology, called a wet particulate scrubber, uses a slurry of water and previously collected fly ash to remove fly ash as the flue gas passes through a venturi (a short tube with a constricted cross section). Intimate contact between the slurry, which is recirculated at a high rate, and the flue gas causes the fly ash particles to transfer from the gas to the slurry. In the process, the hot (~300°F) flue gas is cooled to about 120°F and saturated with moisture.

Fans are required to feed air to the boilers to support combustion, and to draw flue gases out of the boiler. These fans must also overcome the resistance to flue gas flow provided by the particulate control devices. ESPs usually have the least resistance to flow, while wet particulate scrubbers have the highest.

Sulfur Dioxide Control

Sulfur in coal is oxidized during the combustion process to produce sulfur dioxide (SO_2), and often a small percentage of sulfur trioxide (SO_3). These are both present as gases rather than solids as the flue gas leaves the boiler, and can combine with moisture in the atmosphere to form acids. Depending on the age of the plant and the amount of sulfur in the coal, the plant may also have a technology installed to capture sulfur dioxide in the flue gas. Often this process involves a wet scrubber. When the wet scrubber is used only for sulfur dioxide control, a venturi may not be used, as was described above for particulate control, but the scrubber may consist of a more open vessel where the flue gas flows upward and a slurry is sprayed downward to contact the gas. This type of scrubber vessel is also called an absorber. In these scrubbers, lime or finely ground limestone is added to the slurry to provide the alkalinity (basic species) to neutralize the acidic sulfur dioxide as it is scrubbed. This acid-base neutralization produces a calcium-based salt as a byproduct, either calcium sulfite hemihydrate, which is typically landfilled or impounded in wet ponds for disposal, or gypsum (calcium sulfate dehydrate), which can be reused to make wallboard such as is used in homes. The slurry being recirculated through the spray nozzles in the scrubber is a mixture of lime or limestone, calcium sulfite and/or gypsum.

Wet particulate scrubbers can also remove SO_2 from the flue gas due to acid-base reactions within the slurry. In some wet particulate scrubbers, lime or finely ground limestone is added to the slurry to increase the amount of alkalinity available and to increase the amount of SO_2 capture realized. In these cases, the slurry being recirculated through the venturi is a mixture of fly ash, lime or limestone, and calcium sulfite and/or gypsum.

Nitrogen Oxides Control

Coal also contains nitrogen as an impurity. When the coal is fired, this nitrogen can be converted to nitrogen oxides. Some of the nitrogen in the air used to combust the coal can also be converted to nitrogen oxides in the boiler. Nitrogen oxides in the atmosphere can react to form ozone and/or fine particulate matter. Consequently, many coal-fired units have technologies installed to control nitrogen oxide emissions. One common technology is selective catalytic reduction (SCR). In SCR systems, catalysts are used to promote chemical reactions between nitrogen oxides in the flue gas and ammonia injected into the flue gas. Catalysts are materials that participate in chemical reactions and allow them to proceed more rapidly, but are not consumed in the reaction. In the catalytic reaction, ammonia is consumed and nitrogen oxides are chemically reduced to form nitrogen and water vapor. The SCR reactions proceed most rapidly at elevated flue gas temperatures (~700°F), so most SCRs are installed in the flue gas path upstream of the ESP (or fabric filter) or wet scrubber.

SCR catalysts are known to oxidize mercury in the flue gas under the right conditions, which is important for mercury capture in wet scrubbers. This is described later in this appendix.

Mercury Control

Mercury in coal is commonly associated with both organic (carbon-containing) and inorganic (mineral matter) components. However, regardless of its mode of occurrence in coal, it all converts to elemental mercury (Hg^0) at the high temperatures in the furnace of a coal-fired boiler. Elemental mercury can exist as a liquid at room temperature (e.g., the heavy silver liquid used in thermometers and thermostats), but has a high vapor pressure, and thus exists as a vapor in dilute quantities in flue gas at furnace temperatures. The flue gas cools as it passes through the boiler, and chemical equilibrium begins to favor oxidized mercury (Hg^{+2}) as the predominant mercury form. Oxidized mercury also has a relatively high vapor pressure and remains in the vapor phase.

Although chemical equilibrium favors oxidized mercury, chemical reaction kinetics (the rate at which elemental mercury is converted to oxidized mercury) may limit oxidation due to the availability of reactants and/or inadequate residence time at lower temperature. Some researchers believe the predominant mercury oxidation reaction in flue gases is with hydrochloric acid (HCl) and oxygen (O_2). The hydrochloric acid is formed from chlorine in the coal during combustion, while the oxygen source is the air used to support the coal combustion. Other researchers believe direct reaction between elemental mercury and chlorine gas (Cl_2) is a predominant pathway for mercury oxidation. Most of the chlorine in coal is converted to hydrochloric acid in flue gas; only a very small fraction is present as chlorine gas. However, reactions with chlorine gas proceed much more rapidly than with hydrochloric acid, and may substantially contribute to mercury oxidation.

Measurements over the past 15 years have shown that coals with low chlorine content (such as Powder River Basin coal, with less than 100 ppm of chlorine) produce mostly elemental mercury in the flue gas exiting the boiler, while coals with higher chlorine content (such as most eastern bituminous coals) can produce mostly oxidized mercury. The percent conversion of elemental to oxidized mercury is also affected by a number of other variables, such as flue gas residence time versus temperature profile and the presence of catalytic material such as certain fly ashes.

The percent oxidation of mercury and the presence of hydrochloric acid in the flue gas, which tend to be closely related, also impact mercury capture in downstream air emissions control devices.

There are two primary removal processes for mercury in the coal-fired in a boiler. One is to adsorb mercury from the flue gas. Adsorption is defined as a process where a gas, vapor or dissolved matter is assimilated by the surface of a solid or liquid. One method of adsorbing mercury is by pneumatically injecting a fine powder of activated carbon into the flue gas duct upstream of the particulate device. Activated carbon is made from coal or lignite that is processed with heat and steam to produce a highly porous material. The fact that it is porous gives it a high surface area per weight of carbon, and this high surface area provides a great capacity for adsorption. Mercury in the flue gas can adsorb onto the highly porous carbon particles and be collected along with the carbon in the unit's particulate control device.

Unburned carbon in fly ash can make it also capable of physically adsorbing mercury. Most fly ash is composed of non-combustible minerals that are found in the coal. These minerals have little capacity to adsorb mercury. Some boilers and some coals produce elevated levels of unburned carbon in the fly ash. In some flue gas environments, as described below, unburned carbon has the capacity to adsorb mercury. The unburned carbon, including adsorbed mercury, is subsequently collected along with fly ash in the particulate control device.

The other primary mechanism for removing mercury introduced by the coal-fired in the boiler is to absorb it in a wet scrubber, where water-soluble oxidized mercury is taken up by the liquid being contacted with the flue gas. Elemental mercury is relatively insoluble in water and is typically not absorbed.

Both the adsorption and absorption mechanisms are discussed further below.

Mercury Adsorption

As mentioned above, mercury can be adsorbed onto carbon that is present in the flue gas either as unburned carbon from the combustion process or as activated carbon powder injected for mercury capture. Higher mercury capture by carbon has been observed with flue gases having elevated HCl concentrations, due to the beneficial impact of chlorine on carbon reactivity. This improvement in carbon performance is believed to result from a process called "chemisorption," where mercury adsorbs onto the carbon surface then undergoes a chemical reaction.

Carbon vendors are developing specialized carbons intended to minimize coal chlorine effects. For example, Norit Americas and Sorbent Technologies Corporation both have developed chemically treated carbons that are more effective than conventional activated carbons in flue gases with low hydrochloric acid concentrations. These chemically treated carbons typically are treated with bromine, another halogen material like chlorine that has proven to be cost effective for improving carbon adsorption activity in low-chlorine flue gases.

There is growing evidence that sulfur trioxide (SO_3) in flue gas adversely affects the performance of activated carbon injected for mercury control, and adversely affects the amount of mercury adsorbed by unburned carbon in fly ash. As described above, most of the coal sulfur is converted to sulfur dioxide (SO_2) when the coal is burned in the boiler, but a small percentage (typically 0.5 to 1.5%) is further oxidized to form sulfur trioxide (SO_3).. Selective catalytic reduction (SCR) for control of nitrogen oxides in the flue gas employs catalysts that can also oxidize a percentage of flue gas SO_2 to SO_3 (typically 0.5 to 1.0%). Thus, in a plant that fires bituminous coal and that has SCR, as much as 2.5% of the coal sulfur can be present in the flue gas as SO_3. As the flue gas cools, this SO_3 combines with flue gas moisture vapor to form vapor-phase sulfuric acid (H_2SO_4). This SO_3/sulfuric acid also adsorbs on carbons, and effectively competes with mercury for adsorption sites. Since there is typically much more SO_3 in the flue gas than mercury, the presence of SO_3 in the flue gas can greatly limit the effectiveness of activated carbon injection for mercury capture.

In addition, mercury adsorption onto carbon depends on flue gas temperature and the amount of flue gas/carbon contact. Low flue gas temperatures and highly effective flue gas/carbon contact enhance mercury capture. As the flue gas temperature increases above approximately 350 °F, the effectiveness of unburned carbon or activated carbon at mercury capture is rapidly diminished, and above approximately 400 °F conventional carbon injection is relatively ineffective.

As for flue gas contact, fabric filters tend to be the most effective, as the flue gas passes directly through filter bags that contain collected fly ash and carbon on their surface. These filter bags serve as a fixed bed of injected carbon, resulting in intimate flue gas/carbon contacting. ESPs are somewhat less effective than fabric filters as a gas/carbon contactor, as once the carbon particles are collected on collecting plates, the flue gas flows beside the layer of carbon particles rather than through it. Wet particulate scrubbers appear to be even less effective flue gas/carbon contactors. The wet scrubber provides no additional contact between the carbon and flue gas than what is achieved "in flight" after the carbon is injected into the gas stream, and there is some evidence that adsorbed carbon may even be released from the sorbent in the scrubber.

Mercury Absorption

Oxidized mercury is water-soluble and is readily collected by wet scrubbers, whereas elemental mercury is insoluble and is not scrubbed at significant percentages. One method of improving mercury capture in a plant that is equipped with a wet scrubber is to increase the percent of the mercury in the flue gas that is present in the oxidized rather than the elemental form.

As mentioned earlier, eastern bituminous coals with high chloride content (greater than 100 ppm chloride in the coal) tend to produce mostly oxidized mercury in the flue gas. Furthermore, SCR systems contain oxidation catalysts that can also promote mercury oxidation for eastern bituminous coals. However, it appears that catalyst conditions that favor SO_2 to SO_3 oxidation are also the conditions that favor mercury oxidation. Many SCR catalyst vendors have developed low SO_2 oxidation catalyst formulations, to help avoid problems associated with high SO_3 concentrations in flue gas. It appears that these low SO_2 conversion catalysts are less effective at oxidizing mercury.

For boilers burning low chlorine coals (such as Powder River Basin coals with less than 100 ppm chlorine in the coal and less than 1 ppm HCl in the flue gas), there appears to be very little mercury oxidation by most SCR catalysts. However, high mercury oxidation catalysts are under development.

Other technologies have been developed and/or are being developed to promote mercury oxidation upstream of wet scrubbers. Several are described below. Also, there are competing effects that can limit the net capture of oxidized mercury by wet scrubbers. These effects and efforts to control these limitations are also described below.

Chemical Injection

One technology for enhancing mercury oxidation is to add halogens such as chlorine or bromine to the coal. Halogen salts such as calcium chloride ($CaCl_2$) or calcium bromide ($CaBr_2$) can be added to the coal or injected as a liquid solution directly into the boiler furnace as a means of supplementing the coal chlorine content. Halogen injection tests have been conducted on approximately one dozen coal-fired units in the U.S., in short term tests of 30 days or less. No U.S. coal-fired unit currently injects halogens on a full-time basis as a mercury control technology.

Salts added with the coal or injected into the furnace decompose at furnace temperatures to form vapor-phase acids (hydrochloric acid [HCl] or hydrogen bromide [HBr]) in the flue gas. These vapor-phase halogen acids react with elemental mercury to produce oxidized mercury that can be removed by a downstream wet scrubber. Full-scale tests have been conducted on a number of coal-fired units that fire Powder River Basin coal, Texas lignite, and North Dakota lignite, for test durations of up to 30 days. The results have shown that injecting chloride salts in this manner can produce mercury oxidation percentages as high as 90%.

Results have also shown that calcium bromide can be injected at lower concentrations of bromine than the concentrations of chlorine required to produce similar oxidation percentages. Most of the full-scale test results have shown that calcium bromide injection would be more cost effective than calcium chloride injection when the delivered costs of the salts are considered. However, existing patents on the use of bromine to oxidize mercury may require royalty payments to the patent holder. Thus, there are a number of uncertainties associated the cost of calcium bromide injection.

Also, this testing has only been conducted on U.S. units that fire western low chloride coals such as Powder River Basin coal or lignite. No U.S. testing has been conducted to explore the effectiveness of halogen injection in maximizing mercury oxidation in units that fire eastern bituminous coal.

Mercury Oxidation Catalysts

Another approach is to use catalysts to enhance the ability of the small amount of HCl in flue gas from low-chlorine coals to oxidize mercury. Catalysts are materials that participate in chemical reactions and allow them to proceed more rapidly, but are not consumed in the reaction. Catalysts have been identified that promote the oxidation of elemental mercury in flue gases from low-chlorine coals such as PRB. However, catalytic oxidation technology has to date only been tested at pilot scale, and only downstream of fabric filter or ESP particulate control devices and upstream of separate SO_2 control scrubbers. In these applications, the catalysts have been exposed to flue gas that is nearly free of fly ash content.

These oxidation catalysts are typically inserted into the flue gas ducts as "honeycomb"-type structures with many small passages through which the flue gas flows. This provides a large surface area to which the catalyst materials are applied and on which the oxidation reactions can take place. Fly ash has a tendency to plug these small flue gas passages. While it is possible to use structures that have larger passages to avoid fly ash plugging, this requires more honeycomb structure volume to achieve the same surface area. Such configurations have not yet been pilot tested.

The oxidation catalysts have only been tested in flue gases from western fuels such as PRB and lignite, although an ongoing pilot test is being conducted in flue gas from low-sulfur eastern bituminous coal. There has been no pilot scale testing of oxidation catalysts in flue gas from medium- or high-sulfur coal such as is typically fired in Pennsylvania.

Furthermore, there are two caveats about using low-temperature catalysts for achieving high mercury capture percentages. One is that the overall mercury capture percentage may be limited by the net removal of oxidized mercury by the downstream wet scrubber, due to the effects of mercury re-emissions as described below. The second is that oxidation catalysts begin service at their maximum mercury oxidation activity, then lose activity over time due to poisoning effects of other species in the flue gas. With time, the oxidation of elemental mercury across these catalysts tends to decay. To maintain high oxidation percentages over time, either a large excess of catalyst, frequent catalyst replacement, or frequent catalyst regeneration may be required.

Fabric Filter Effects

It has been observed that for several plants that fire low-chlorine coal and that have fabric filters, the flue gas downstream of the fabric filter contains mostly oxidized mercury, whereas the flue gas from such coal downstream of an ESP or wet particulate scrubber contains mostly elemental mercury. This observation suggests that fabric filters serve as a catalyst bed to promote the oxidation of elemental mercury in the flue gas. While the mechanism is not completely understood, it is known that fabric filters function by collecting fly ash from the flue gas as the flue gas passes through the filter bags, as described above. This collected fly ash becomes a fixed bed of material that the flue gas must penetrate. It is believe that some components in the fly ash in this fixed bed serve as a catalyst to promote elemental mercury oxidation. In some instances, a measurable percentage of the flue gas mercury is also removed across the filter bags, most likely due to adsorption by components of the fly ash particles. Example data are shown in the following table.

Table A-1. Effect of Particulate Control Device on Mercury in Flue Gas for Plants that Fire Western Low Chlorine Coals

Plant	Air Emissions Control Configuration	Mercury Removal Across Fabric Filter or ESP (%)	Percent Oxidized Mercury at Fabric Filter or ESP Outlet
Comanche 2	Fabric Filter	66	87
Boswell 2	Fabric Filter	83	80
Intermountain	Fabric Filter followed by Wet Scrubber	34	83
Spruce	Fabric Filter followed by Wet Scrubber	6	94
Parish Unit 8	Fabric Filter followed by Wet Scrubber	21	80
Fayette Unit 3	**ESP** followed by Wet Scrubber	1	27

These data show that for the five example units with fabric filters, the measured mercury oxidation percentage was relatively high (80% or greater) while the oxidation percentage for the plant equipped with an ESP was much lower at 27%.

The data showing mercury oxidation for a plant equipped with a fabric filter and firing PRB coal are based on a limited number of observations. It is not known how variables such as fuel quality, fabric filter type and design parameters, and flue gas temperature impact the fabric filter effects. URS periodically measured how the mercury oxidation varied at one plant that fires 100% PRB coal and has a fabric filter followed by a wet scrubber over a 1.5-year period. Over that period, we observed that the percent oxidized mercury in the flue gas at the fabric filter outlet varied from 60% to 95%, which is a substantial range, for reasons that remain unexplained.

Similarly, little data are available on the effects of fabric filters on mercury oxidation and capture for units that fire eastern bituminous coal. Power plant mercury concentration data collected as part of the U.S. EPA Information Collection Request (ICR) in 1999 showed that for four plants that fire eastern bituminous coal and that have fabric filters for particulate control, the mercury in the fabric filter outlet flue gas ranged from being 46% oxidized to 79% oxidized. This is surprisingly lower than the data shown above for fabric filters on low-chloride western coal plants, and not appreciably higher than the ICR data for plants that fire eastern bituminous coal and have ESPs for particulate control. We note the DEP refers to an October 25, 2000, prepared by EPA "Control of Mercury Emissions from Coal-fired Electric Utility Boilers" in which the claim is made that a unit equipped with a cold-side fabric filter with wet scrubber achieved 96% reduction in total mercury emissions. The report does not contain any citation as to the unit and conditions under which this reduction was made. Recent data as reported above do not show this level of mercury reduction.

Mercury Capture by Wet Scrubbers

A number of full-scale plant measurements have shown that wet scrubbers installed for sulfur dioxide control can remove a high percentage of the water-soluble, oxidized mercury in a flue gas and typically remove little elemental mercury. However, removal of oxidized mercury by wet scrubbers can be limited by a phenomenon called "re-emissions." This phenomenon results in a portion of the scrubbed oxidized mercury being chemically reduced to elemental mercury in the scrubber liquor. Once reduced, the insoluble elemental mercury is released back into the flue gas.

Because of the effects of mercury re-emissions, technologies that promote high percentages of oxidized mercury in flue gas, such as halogen injection with the coal, SCR, or mercury oxidation catalysts do not necessarily guarantee high overall removal of mercury in the coal.

The re-emissions process is not completely understood at this time, but is believed to occur by reaction with dissolved sulfur dioxide in the scrubber liquor. As more is understood about these reactions, it may be possible to control scrubber chemistry and operating conditions to minimize re-emissions. However, a possible near- term solution is the use of scrubber additives to precipitate scrubbed, oxidized mercury out of the liquid phase before it undergoes reduction reactions. These additives have not been sufficiently demonstrated for this purpose on U.S. coal-fired, scrubbed units though. Until re-emissions are fully understood and/or scrubber additives are demonstrated to be effective, the net mercury removal that can be achieved with a wet scrubber will remain in question.

Appendix B – Overview of Mercury Control Technology Development Progress

DOE/NETL initiated pilot-scale and full-scale field-testing of mercury control technologies at coal-fired power plants in 2001. While the scale of testing has, in some cases, been large it has still been considered a research and development activity rather than commercial operation. Phase I field testing during 2001–04 included an evaluation of ACI at various power plants and some of the results are presented in the table as follows:

Table B-1. Field Testing of Mercury Control Technologies for Coal-Fired Power Plants

Mercury Control Technology	Air Pollution Control Device Configuration	Hg Control Eff.(%)	Power Plant	Type of Coal	Test Date	URS Confidence in Projected Performance at PPL
1] Baseline	SDA/FF	12	Holcomb	PRB	3Q/2004	
2] Coal Blending (0 to 15% Bituminous)	SDA/FF	12 - 80	Holcomb	PRB		H
3] ACI - Conventional PAC (1 lb/MMacf)+ Chemical Additive KNX	SDA/FF	50 86	Holcomb	PRB		M
4] ACI – Activated PAC (1 lb/MMacf)	SDA/FF	50	Holcomb	PRB		M
5] ACI - Brominated PAC (0.7 – 4.3 lb/MMacf)	SDA/FF	77 - 90	Holcomb	PRB		M
6] Baseline	ESP	15	Meramec	PRB	4Q/2004	M
7] ACI - Conventional PAC (5 lb/MMacf)+ Chemical Additive KNX	ESP (320 SCA)	74 87	Meramec	PRB	4Q/2004	M
8] ACI - Activated PAC (3.2 lb/MMacf)	ESP	97	Meramec	PRB	30-day	L
9] Baseline	ESP	15	Leland	Lignite	3Q/2004	
10] ACI – PAC (3lb/MMacf) + Chloride Injection 500 ppm (7lb/MMacf)	ESP (320 SCA)	45 65	Leland	Lignite		

Table B-1 (continued).

Mercury Control Technology	Air Pollution Control Device Config-uration	Hg Control Eff.(%)	Power Plant	Type of Coal	Test Date	URS Confidence in Projected Performance at PPL
11] Baseline	SDA/FF	10	Stanton	Lignite	3Q/2004	
12] ACI – PAC (6 lb/MMacf)	SDA/FF	75	Stanton	Lignite		
13] ACI – Brominated PAC (1.5 lb/MMacf)	SDA/FF	90	Stanton	Lignite		
14] ACI – DARCO Hg-LH PAC (0.7 lb/MMacf)	SDA/FF	60	Stanton	Lignite		
15] MerCAP-Untreated Adsorption Process	SDA/FF	15 - 30	Stanton	PRB	1035 hours	
16] MerCAP- Acid-treated Adsorption	SDA/FF	30 - 35	Stanton	PRB	3123 hours	
17] Baseline	ESP/FGD	15	Coal Creek	Lignite		
18] Catalyst Pd #1	ESP/FGD	65	Coal Creek	Lignite	20 months	M
19] Catalyst Carbon #6	ESP/FGD	80	Coal Creek	Lignite	13 months	M
20] Baseline	CS-ESP/ FGD	50	Yates Unit 1	Bitumi nous	4Q/2004	
21] ACI – Coarse HOK Sorbent (16.2 lb/MMacf)	CS-ESP/ FGD	77	Yates Unit 1	Bitumi nous	4Q/2004	M
22] ACI – DARCO Hg-LH Brominated (10.4 lb/MMacf)	CS-ESP/ FGD	82	Yates Unit 1	Bitumi nous	4Q/2004	M

Mercury control via ACI upstream of the existing particulate control device will result in commingling of the PAC and fly ash, which could potentially have an adverse effect on the marketability of the fly ash. Primarily, the increase in cost of electricity (COE) resulting from mercury control via ACI is determined by annual PAC consumption costs, which are dependent on the ACI concentration required to achieve a given level of mercury control and the current delivered PAC cost. DOE found that the 20-year annualized incremental increase in COE varied from 0.14 mills/kWh to 3.92 mills/kWh. The lower bound (0.14 mills/kWh) corresponds to 50% mercury removal due to brominated DARCO® Hg-LH injection at Holcomb Station Unit 1 when byproduct impacts are excluded, while the upper bound (3.92 mills/kWh) was calculated for 70% mercury removal due to conventional DARCO® Hg injection in conjunction with SEA coal treatment (chemical injection) at Leland Olds Unit 1 with the inclusion of byproduct impacts.

The incremental cost of mercury reduction, i.e., the cost (in \$/lb Hg removed) to achieve a specific reduction is impacted largely by the level of baseline mercury capture exhibited by the existing APCD configuration and the coal mercury content (lb/TBtu). For example, the incremental cost of mercury control (in \$/lb removed) will increase when: (1) baseline mercury capture by existing APCD is high; or (2) the coal mercury content is low, because a smaller quantity of mercury is removed from the flue gas for a given level of control. For DOE's analysis, the 20-year annualized incremental cost of mercury control varies from \$3,810/lb Hg removed to \$166,000/lb Hg removed. The lower bound (\$3,810/lb Hg removed) corresponds to 70% mercury removal due to DARCO® Hg-LH injection at Holcomb Station Unit 1 when byproduct impacts are excluded, while the upper bound (\$166,000/lb Hg removed) was calculated for 50% mercury removal due to conventional Super HOK injection at Plant Yates Unit 1 with the inclusion of byproduct impacts.

The cost of mercury control via ACI for each of the field-testing units presented in the table is summarized as follows:

Holcomb Station Unit 1

The cost of mercury control for this 360 megawatt (MW) subbituminous-fired unit equipped with an SDA/FF configuration is based on the performance of brominated DARCO® Hg-LH during full-scale parametric and long-term field tests. During the long-term continuous injection trial, an average total mercury removal of 93% was achieved with an average DARCO® Hg-LH injection concentration of 1.2 lb/MMacf. The following key points summarize the economics of mercury control for this unit.

- The installed capital cost of the ACI system is approximately \$1,310,000 or \$3.63 per kilowatt (\$/kW) on a unit capacity basis.
- A DARCO® Hg-LH injection concentration of 1.03 lb/MMacf is required to achieve 90% ACI mercury removal resulting in an annual PAC consumption cost of approximately \$493,000 using the current delivered price of \$0.95/lb.
  1. When byproduct impacts are excluded, this level of control yields an increase in COE of 0.37 mills/kWh and an incremental cost of \$6,060/lb Hg removed.
  2. The inclusion of byproduct impacts results in an increase in COE of 1.09 mills/kWh and an incremental cost of \$18,000/lb Hg removed.

Meramec Station Unit 2

The cost of mercury control for this 140 MW subbituminous-fired unit equipped with a CS-ESP is based on the performance of DARCO® Hg-LH during full-scale parametric and long-term field tests. During long-term testing, an average DARCO® Hg-LH injection concentration of 3.3 lb/MMacf was required to achieve an average total mercury removal of 93%. The following points summarize the economics for this unit.

- The installed capital cost of the ACI system is approximately \$1,280,000 or \$9.16/kW on a unit capacity basis.

- A DARCO® Hg-LH injection concentration of 2.40 lb/MMacf is required to achieve 90% ACI mercury removal resulting in an annual PAC consumption cost of approximately $532,000.
    1. When byproduct impacts are excluded, this level of control yields an increase in COE of 0.99 mills/kWh and an incremental cost of $17,700/lb Hg removed.
    2. The inclusion of byproduct impacts results in an increase in COE of 2.37 mills/kWh and an incremental cost of $42,500/lb Hg removed.

Leland Olds Unit 1

For this 220 MW North Dakota (ND) lignite-fired unit equipped with a cold-side ESP, the cost of mercury control is based on the mercury capture efficiency of conventional DARCO® Hg injection when the coal is treated with an SEA (i.e., an aqueous calcium chloride ($CaCl_2$) solution) prior to combustion. During long-term testing, an average total mercury removal of 63% was achieved with an average DARCO® Hg injection concentration of 3 lb/MMacf coupled with the addition of an aqueous $CaCl_2$ solution to the coal at a constant rate that is equivalent to adding approximately 500 parts per million (ppm) chlorine to the coal. The following points summarize the economics for this unit.

- The installed capital cost of the SEA and ACI systems is approximately $1,390,000 or $6.33/kW on a unit capacity basis.
- The delivered $CaCl_2$ cost of $0.15/lb, which includes $0.10/lb for transportation expenses, yields an annual SEA consumption cost of approximately $388,000.
- With $CaCl_2$ coal treatment, a DARCO® Hg injection concentration of 4.39 lb/MMacf is required to achieve 70% ACI mercury removal resulting in an annual PAC consumption cost of approximately $875,000 using the current delivered price of $0.54/lb.
    1. When byproduct impacts are excluded, this level of control yields an increase in COE of 1.25 mills/kWh and an incremental cost of $22,200/lb Hg removed.
    2. The inclusion of byproduct impacts results in an increase in COE of 3.92 mills/kWh and an incremental cost of $69,600/lb Hg removed.

Stanton Station Unit 10

The cost of mercury control for this 60 MW ND lignite-fired unit equipped with an SDA/FF configuration is based on the performance of DARCO® Hg-LH during full-scale parametric and long-term field tests. During long-term testing, an average DARCO® Hg-LH injection concentration of 0.7 lb/MMacf was required to achieve an average total mercury removal of 60%. The following points summarize the economics for this unit.

- The installed capital cost of the ACI system is approximately $1,270,000 or $21.10/kW on a unit capacity basis.

- A DARCO® Hg-LH injection concentration of 1.15 lb/MMacf is required to achieve 70% ACI mercury removal resulting in an annual PAC consumption cost of approximately $116,000.
  1. When byproduct impacts are excluded, this level of control yields an increase in COE of 1.02 mills/kWh and an incremental cost of $17,400/lb Hg removed.
  2. The inclusion of byproduct impacts results in an increase in COE of 2.77 mills/kWh and an incremental cost of $47,300/lb Hg removed.

Plant Yates Unit 1

The cost of mercury control for this 100 MW bituminous-fired unit equipped with a CS-ESP is based on the performance of conventional Super HOK during full-scale parametric and long-term field tests. During long-term testing, Super HOK injection concentration of 4.5 lb/MMacf, 6.5 lb/MMacf, and 9.5 lb/MMacf were required to achieve average levels of total mercury control of approximately 68%, 75%, and 76% respectively. The following key points summarize the economics for this unit.

- The installed capital cost of the ACI system is approximately $1,270,000 or $12.66/kW on a unit capacity basis.
- A Super HOK injection concentration of 8.98 lb/MMacf is required to achieve 70% ACI mercury removal resulting in an annual PAC consumption cost of approximately $707,000 using the current delivered price of $0.39/lb.
  1. When byproduct impacts are excluded, this level of control yields an increase in COE of 1.72 mills/kWh and an incremental cost of $69,500/lb Hg removed.
  2. The inclusion of byproduct impacts results in an increase in COE of 3.69 mills/kWh and an incremental cost of $149,000/lb Hg removed.

Appendix C – Glossary and Definition of Acronyms

Absorber	A vessel used in flue gas desulfurization systems wherein flue gas is contacted with a recirculating liquid or slurry (liquid plus solids) stream. As a result of this contact, gaseous species are transferred from the flue gas to the liquid.
acfm	Actual cubic feet per minute. Measure of flow through a pipe or duct.
ACI	Activated Carbon Injection. A process in which activated carbon powder is suspended in an air stream, then injected into a flue gas duct. Activated carbon is produced from carbon-containing materials such as coal, lignite, or coconut shells, by treatment with heat and steam. The resulting material has a high internal surface area that makes it more effective at adsorbing species from the flue gas. The injected carbon contacts the combustion flue gas and subsequently adsorbs gas-phase mercury, then is removed from the flue gas by a particulate control device. The extent of mercury removal is determined by a number of factors, including activated carbon properties, the amount of carbon injected, the composition and temperature of the flue gas, and the contact time within the flue gas duct.
Adsorption	A physical process where by a gaseous or vaporous substance, or a dissolved species, is assimilated or taken up by the surface of a solid.
Air Heater	A piece of equipment on a boiler that is used to recover heat from the combustion flue gas exiting a boiler. The air heater is a heat exchanger that transfers heat from the flue gas leaving the boiler to the air going to the boiler to support the combustion of coal. Most air heaters on coal-fired utility boilers cool the combustion flue gas from greater than 700°F to less than 350°F.
Baghouse	Also called a fabric filter. An environmental control unit that contains fabric bags, through which flue gas flows to collect and remove particulate matter from the flue gas. The particulate matter collects in a layer (filter cake) that builds up at the bag surface. The filter bags are periodically cleaned by either temporarily reversing the gas flow across the filter or by blowing a pulse of compressed air backwards (opposite the direction of flue gas flow) through the filter. The ash removed from the bag falls into a hopper located at the bottom of the baghouse for subsequent removal and disposal.
Brominated	Term used to describe the impregnation of sorbent materials such as activated carbon with bromine, a halogen material somewhat similar to chlorine.
Btu	British Thermal Unit. Measure of heat produced from burning a fuel, such as coal.

$CaBr_2$	Chemical formula for calcium bromide. In a chemical addition process, calcium bromide can be added to the fuel coal or injected directly into the boiler to increase the oxidation of mercury in the resulting flue gas.
$CaCl_2$	Chemical formula for calcium chloride. In a chemical addition process, calcium chloride can be added to the fuel coal or injected directly to the boiler to increase the oxidation of mercury in the resulting flue gas.
CAIR	Clean Air Interstate Rule. Rule issued by the U.S. EPA on March 10, 2005 designed to permanently cap emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx) in the eastern United States.
CAMR	Clean Air Mercury Rule. Rule issued by U.S. EPA on March 15, 2005 to permanently cap and reduce mercury emissions from U.S. coal-fired power plants. When fully implemented, the two-phase rule will reduce utility emissions of mercury from 48 tons a year to 15 tons, a reduction of nearly 70 percent. Each state has a designated emission reduction level that must be met under the rule. The federal rule includes provisions for a cap and trade program. Each state will determine how its emission limits are to met and if and how resident power plants may participate in the cap and trade program.
Cap and Trade	A regulatory approach where emissions of a particular species within a geographic region is limited to a specified value. This limit is achieved by providing individual emission sources within the region an "allowance" to emit a specified quantity of that species. Emission sources within the region may trade allowances under a free-market system whereby the pricing is controlled by supply and demand, to achieve compliance in the most cost effective manner. Individual emission sources may choose to control emissions to their specified value, control to a lower value and sell excess allowances, or control to a higher value and purchase allowances as needed to achieve compliance.
Catalyst	A species that participates in a chemical reaction, allowing it to proceed to completion more rapidly, but is not consumed by the reaction.
CCB	Coal combustion byproducts. The residue that remains after pulverized coal is burned. This typically includes the coal ash and reaction byproducts from the capture of sulfur dioxide from the flue gas.
CCPI	Clean Coal Power Initiative. An initiative of the U.S. Department of Energy, and funded by Congress, to support the demonstration of technologies aimed at reducing emissions caused by the combustion of coal. Projects funded under this initiative are typically full-scale and long-term in nature. A recent example is the demonstration of Toxecon^{TM} technology for mercury control at We-Energy's PRB coal-fired Presque Isle power plant in Wisconsin.

Chemical Addition:	A mercury control technology where halogen-containing salts, such as calcium chloride or calcium bromide, are added to the fuel coal or injected directly into the coal-fired boiler to increase the oxidation of mercury in the resulting flue gas. Halogen species, such as chlorine or bromine, react with mercury in the flue gas as it cools downstream of the boiler, resulting in some fraction of the elemental mercury converting to an oxidized form in the gas. Oxidized forms of mercury are effectively removed across wet scrubbers whereas elemental mercury is not. This technology is believed to be applicable primarily to power plants firing low-chloride coals such as Western subbituminous (e.g., PRB) or lignite.
Cl	Chemical symbol for chlorine. Typically found in coal, its concentration is believed to play a large role in determining the fraction of flue gas mercury present in the elemental versus oxidized forms. It also can affect the amount of mercury that can be adsorbed by activated carbons that are not impregnated with halogen species and the amount of mercury that can be removed by unburned carbon remaining in the coal fly ash.
Coal Seam	A stratum of coal thick enough to be mined cost-effectively. Coal seams can vary appreciably in thickness and length. Coal properties can vary, particularly mercury concentrations, from one coal seam to another even within the same mine.
CO_2	Chemical formula for carbon dioxide. A byproduct of all combustion processes.
Combustion Modifications	Changes made to the combustion properties of a boiler in order to change the efficiency of the boiler or to change properties of the resulting fly ash or flue gas. The use of combustion modifications is currently being evaluated as a way to decrease mercury emissions at a given plant. Here, the nature of the fuel (e.g., fuel blending) or the ratio of combustion air to fuel may be modified in an attempt to change the level or speciation (e.g., oxidation) of mercury in the resulting flue gas, or to change the nature of the fly ash produced. In the latter case, changes are made to increase the unburned carbon content present in the fly ash to increase its reactivity with mercury; the trade-off in this case is less efficient use of the coal fed to the boiler.
DOE	U.S. Department of Energy
ESP	Electrostatic precipitator. Environmental control that uses electrically energized plates to remove particulate matter, such as fly ash, from combustion flue gas. Particulate matter becomes charged as it enters the ESP and is then captured as it becomes attracted to and then adsorbed to the plates. The plates are periodically physically rapped to dislodge the attracted particulate from the plate surface. The particulate matter then drops to the bottom of the ESP where it is collected in hoppers for subsequent removal.

EPA	U.S. Environmental Protection Agency.
EPRI	Electric Power Research Institute.
Fabric Filter	see "Baghouse"
FGD	Flue gas desulfurization. Environmental control process used to remove sulfur dioxide (SO_2) from combustion flue gas. In this process, an alkaline reagent, such as ground limestone or slaked lime, is sprayed into a large reactor vessel where it contacts the flue gas. The SO_2 in the flue gas reacts with the reagent and is subsequently removed from the gas. FGD system can be operated either dry (e.g., produce a dry byproduct removed in an ESP or baghouse particulate control device) or wet (e.g., produce a dissolved solid or a suspended solid in an aqueous solution). Typical byproducts of FGD systems include gypsum (calcium sulfate dehydrate) or calcium sulfite hemihydrate. In some cases, gypsum is sold for reuse in processes such as wallboard manufacturing. FGD systems are typically effective at removing oxidized forms of mercury from flue gas but are ineffective at removing elemental mercury.
FGD Liquor	The aqueous (water-based) phase of a wet FGD reactor slurry. This phase is comprised of the dissolved species absorbed from the flue gas or added to the system as a process reagent. The dissolved species, such as calcium and sulfate, become saturated within the liquor as more flue gas is treated resulting in the formation (e.g., precipitation) of byproduct solids.
Flue Gas	The gas produced from the combustion of fuels, such as coal, containing the gaseous and most of the particulate byproducts (ash) from the combustion process. The gaseous components include excess oxygen from the combustion air, nitrogen from the combustion air, carbon dioxide (the product of combustion of the carbon in the fuel), moisture, and trace species such as sulfur dioxide (the product of combustion of sulfur in the fuel, HCl (the product of combustion of chlorine in the fuel), nitrogen oxides (from combustion of nitrogen in the fuel and conversion of nitrogen in the combustion air) and mercury. Flue gas exits the boiler at a very high temperature (>2000°F) and is cooled as it passes across the air heater and environmental controls to 125°F to 350°F, depending on the specific controls installed, before exiting through the stack. Particulate matter is removed from flue gas using electrostatic precipitators, fabric filters or wet particulate scrubbers. Nitrogen oxides are removed from flue gas using high-temperature (e.g., 700°-800°F) catalysts and/or ammonia injection systems. Sulfur dioxide and hydrogen chloride are removed from flue gas using wet- or dry FGD systems.
Fly Ash	A coal combustion byproduct that consists of incombustible matter present in the coal. During combustion, the material becomes fused into an amorphous (not

	crystaline) glassy solid structure typically shaped like a sphere that is 1 to 100 micrometers in diameter. The resulting particles are removed from the gas by electrostatic precipitators, fabric filters or wet particulate scrubbers. The ash content of coal can range from 2 to 30%. In pulverized coal boilers, where the coal is finely ground prior to combustion, most of the fly ash (e.g., 75-85%) typically exits the boiler in the flue gas. Fly ash is comprised mainly of oxides of silicon, aluminum, and iron and usually contains a wide variety of trace species, including heavy metals.
Fly Ash Reuse	Some fly ash produced by coal combustion units is sold for reuse in a variety of industrial products such as concrete and pavement. The ability to reuse fly ash depends upon its properties, most notably the alkalinity and concentration of unburned carbon present in the ash. According to the American Coal Ash Association, over 75 million tons of coal fly ash were sold in 2002. Benefits of fly ash re-use include decreasing the amount of byproduct sent to disposal (typically in landfills) as well as decreases in the need for more expensive production materials that fly ash replaces such as cement or lime. Furthermore, an energy savings is associated with not having to produce the alternative materials. Fly ash-containing concrete is typically stronger than that not containing fly ash.
Halogen	A group of five chemically related nonmetallic elements that include fluorine, chlorine, bromine, iodine, and astatine.
H_2S	Chemical formula for Hydrogen Sulfide.
HBr	Chemical formula for Hydrogen Bromide.
HCl	Hydrochloric acid. A byproduct of the combustion process which the primary form taken by the chlorine entering the boiler with the coal.
Hg	Atomic symbol for mercury
Hg^0	Elemental Mercury. One of the forms that gaseous mercury can take. Elemental mercury is not soluble in water-based solutions (e.g., not removed across wet FGD systems or wet particulate scrubbers) and is typically less likely to be removed from flue gas with fly ash than other mercury forms
Hg^{+2}	Divalent form of mercury. Term often used to refer to 'oxidized' forms of mercury present in a combustion flue gas.
ID Fan	Induced draft fan. A large industrial fan used to withdraw flue gas from a boiler and force it up the emissions stack. Also generally provides the motive force to pull or push flue gas through air emissions control equipment such as ESPs, fabric filters, and wet FGD systems.

LOI	Loss on Ignition. The fraction of the fly ash consisting of unburned carbon and other combustible material that does not completely burn in a coal-fired boiler.
Minemouth	An industrial plant that is located adjacent to the location where the raw material processed by that plant is withdrawn from the ground. Often refers to power plants that are located next to the mine that is the source of its coal fuel.
Monte Carlo Simulation	A statistical approach wherein an event that produces a random answer is repeated a large number of times and the answers are recorded. The answers are then analyzed to determine the probability that a given answer will result for any one time the event happens.
MW	Megawatt. A unit of power equal to one million watts (e.g., 1,340 horsepower)
NO_x	Nitrogen oxide compounds. Term used to refer to total concentration of nitrogen oxide compounds, including species such as nitrogen oxide (NO) and nitrogen dioxide (NO_2), in a given process gas. Nitrogen oxide compounds are formed from nitrogen in the fuel and nitrogen in the combustion air during the combustion of various fuels such as coal.
Opacity:	A measure of the ability of light to pass through flue gas flowing through a duct or out of smoke stack. Most power plants have a regulatory opacity limit that is not to be exceeded. Opacity is increased due to the presence of particulate matter or the formation acid mist within the gas. Opacity may also increase if activated carbon, added for mercury control, is not collected at high efficiency and some penetrates a particular control device.
Oxidation	A term used to describe two types of chemical reaction. One is the combination of a substance with oxygen to form an oxide. The other is a reaction where the atoms in an element lose one or more electrons, causing that element to increase in valence (or positive charge). The latter more broadly describes the oxidation of elemental mercury to form Hg^{+2}, but the former definition can also apply if elemental mercury reacts with oxygen to form an oxide.
Pilot Scale	Refers to a step in the development of new processes where small equipment is used to test a process that will later be implemented on much larger equipment for commercial operation. The pilot-scale equipment is typically designed to simulate the future commercial equipment as well as possible, but there are almost always physical or chemical parameters that will change when the size is increased (or "scaled up"). Pilot-scale tests are often conducted on a slipstream (small percentage of the entire stream) of flue gas at coal-fired power plants.
Pneumatic Injection System:	A system that uses air to transport material. In an activated carbon system, carbon powder is pneumatically added to the gas stream by metering a known mass of the

	material into a stream of air, produced by a blower or compressor, which transports the carbon as a suspended particulate through hoses or pipe to injection points in the flue gas duct.
PRB Coal	Power River Basin coal. Western subbituminous coal mined from the Power River Basin of Wyoming and Montana. Coal from this region typically contains relatively low levels of sulfur, moderate levels of mercury, and very low levels of chlorine. Subbituminous coal also has a lower heat content per mass of coal than bituminous coal, so more must be burned to produce a fixed amount of energy.
ppm	Parts per million. A unit of measure indicating either the mass of a particular species per million mass units in a liquid or solid substance (e.g., grams per million grams), or the volume of a particular species per million volume units of a gas stream.
Pressure Drop	Term referring to the change in static pressure within a flow line (or duct) as a material, often a gas, passes across a component within the flow path. The pressure drop is a result of the resistance to flow imposed by that component.
Pulse-jet Fabric Filter	A fabric filter that is cleaned using a pulse of high-pressure air that is flowed backward across the filter bag (see "Baghouse"). The flue gas flow is normally from outside of the bags to the inside, so fly ash collected on the bag outer surfaces.
Pyrite	Iron sulfide (FeS_2). A brassy yellow mineral common to many rock deposits, including coal. Some data suggests an affinity of mercury toward pyrite deposits. Because of its relative hardness compared to coal, some of the pyrite fraction of coal typically does not become pulverized (as does the coal) and is subsequently rejected by the coal grinding mills prior to the coal being injected into the furnace through burners.
Reduction	The process of being chemically reduced, wherein an element gains electrons to lower its valence state (reduce its positive charge). The opposite of oxidation.
Re-emissions	A phenomenon that occurs with some wet FGD absorbers where absorbed, oxidized mercury is chemically reduced back to insoluble elemental mercury and subsequently released back into the absorber outlet flue gas.
Retrofit	The addition of new equipment after a plant has been built and operated for some time.

Reverse-gas Fabric Filter	A fabric filter that is cleaned using clean flue gas flowed backward across the filter bag (see "Baghouse"). The flue gas flow is normally from the inside of the bags to the outside, so the fly ash collects on the inside bag surfaces.
SCA	Specific Collection Area. Term that refers to the charged plate surface area used to remove particulate, such as fly ash, from combustion flue gases; often presented in units of ft^2 of collecting area per kacfm (1000 acfm) of gas flow.
SCR	Selective Catalyst Reduction. Environmental control device for removing nitrogen oxide compounds from combustion flue gas. The process uses a combination of oxidation catalysts and injected ammonia that contact the flue gas at relatively hot temperatures (typically 650°-800°F) and chemically reduces nitrogen oxide compounds to nitrogen and oxygen. The oxidation catalysts in SCR systems can also oxidize elemental mercury if an adequate concentration of HCl is present in the flue gas.
SO_2	Sulfur Dioxide. Byproduct formed by the oxidation of coal sulfur during the combustion process.
SO_3	Sulfur Trioxide. A sulfur form that is further oxidized compared to sulfur dioxide; forms sulfuric acid when condensed.
TMT-15	Tri-mercapto-s-triazine trisodium salt. A reagent added to wet scrubbers to decrease mercury re-emissions. The reagent works by complexing (e.g., binding tightly) mercury that is present in the aqueous phase of the FGD slurry, thus preventing the mercury from undergoing reactions that cause it to re-volatilize back into the gas-phase.
Toxecon™	A mercury control process developed and trademarked by EPRI that involves the use of activated carbon injection upstream of a secondary baghouse installed downstream of an existing particulate control device such as an ESP. Activated carbon is injected into the flue gas after the ESP but upstream of the new baghouse. The injected carbon adsorbs mercury as it flows through the duct and after it is collected on the fabric filter bags, as the flue gas flows through the bags (see "Baghouse"). Advantages of the Toxecon™ technology include relatively high mercury removal percentages, due to the good contact gas/carbon across the fabric filter, as well as no contamination of the fly ash (by the carbon) that is captured in the primary particulate control device. There is currently one full-scale Toxecon™ process being demonstrated at a PRB-fired power plant.
Toxecon™ II	A mercury control process developed by EPRI that involves the injection of activated carbon into an electrostatic precipitator. The carbon is added to one of the middle fields of a multi-field ESP, where it contacts the flue gas and removes mercury. The carbon is then captured by the downstream fields of the ESP. Potential advantages of this technology include preservation of the bulk of the fly ash (e.g., not contaminated with activated carbon) that is captured in the first

	fields of the ESP, as well as relatively low capital costs. This technology is currently being demonstrated in several short-term full-scale tests.
Venturi	A short tube with a constricted cross section.
Wet Particulate Scrubber	Environmental control process that uses a slurry of water and previously collected fly ash to remove fly ash as the flue gas passes through a venturi (a short tube with a constricted cross section). Intimate contact between the slurry, which is recirculated at a high rate, and the flue gas causes the fly ash particles to transfer from the gas to the slurry. In the process, the hot (~300°F) flue gas is cooled to about 120°F and saturated with moisture. Wet particulate scrubbers can also remove SO_2 from the flue gas, due to acid-base reactions within the slurry.
Wet scrubber	The common name for a vessel where flue gas is contacted with a recirculating liquid or slurry stream to remove impurities from the flue gas. May be used for SO_2 removal (see "FGD"), particulate control (see "Wet Particulate Scrubber"), or both.

AN EVALUATION OF DEPOSITION IN PENNSYLVANIA FOR POTENTIAL MERCURY EMISSION REDUCTION STRATEGIES

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August 25, 2006

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ACRONYMS

BTU	British thermal units
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CMAQ	Community Multiscale Air Quality
EGU	electrical generating utility unit
IPM	Integrated Planning Model
PEBQ	Pennsylvania Environmental Quality Board
PPL	PPL Pennsylvania, LLC
US	United States
USEPA	United States Environmental Protection Agency

1.0 INTRODUCTION

The Pennsylvania Environmental Quality Board (PEQB) is considering adopting a rule (hereafter referred to as the Pennsylvania Mercury Rule) to further reduce mercury emissions from coal or coal-refuse fired electrical generating utility units (EGUs) without allowing emissions trading as provided in the Clean Air Mercury Rule (CAMR) that has recently been promulgated by the United States Environmental Protection Agency (USEPA). The proposed Pennsylvania Mercury Rule will require these reductions starting in 2010, with more stringency by 2015. PPL Generation, LLC (PPL) has retained ENVIRON to evaluate alternative mercury reduction requirements to determine what types of required reductions can meaningfully reduce the deposition of mercury in Pennsylvania.

A particular concern has been raised about the potential for "hot spots" near coal-fired EGUs that could result from mercury deposition absent the proposed Pennsylvania Mercury Rule. In this submittal, we discuss the atmospheric chemistry that leads to mercury deposition in the context of global atmospheric mercury emissions and dispersion. We also discuss the "hot spot" concept in the context of exposure to humans. Mercury in the air is not the main source of mercury exposure to humans. Rather, the main exposure to mercury is through the consumption of food. Mercury reaches the human food chain primarily through fish consumption, as mercury bio-concentrates in fish. Mercury must first deposit, either directly on to a water surface, or in a watershed where it can then be transported to the body of water before it can be incorporated into fish tissues. Therefore, the quantity of mercury deposition is the primary prerequisite of potential impacts of mercury released from EGUs.

ENVIRON conducted mercury deposition modeling for Pennsylvania evaluating three scenarios of mercury control, with particular emphasis on the type of mercury. As is discussed in this report, there are three types of mercury emitted from coal-fired EGUs: elemental mercury, oxidized mercury, and particle-bound mercury. ENVIRON's modeling shows that over 99% of the elemental mercury that is emitted from Pennsylvania's coal-fired EGUs leaves Pennsylvania without deposition, and enters the global pool of mercury. In contrast to that, approximately one-quarter of the oxidized and particle-bound mercury that is emitted from Pennsylvania's EGUs is deposited in Pennsylvania[1]. Particle-bound mercury is already largely controlled in Pennsylvania by existing control equipment (URS, 2006); as a result, particle-bound mercury is not discussed in this report. The control of oxidized mercury in Pennsylvania will reduce deposition of mercury in Pennsylvania, whereas the control of elemental mercury emissions from Pennsylvania's EGUs will do little to reduce mercury deposition in Pennsylvania.

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[1] As is discussed in Appendix B, less than 1% of the merury emitted by Pennsylvania's EGU's is particle-bound

In order to achieve the reduction in total mercury required under the Pennsylvania Mercury Rule, Pennsylvania's EGUs will need to make reductions in both oxidized mercury and elemental mercury (URS 2006).

As will be discussed in this report, an alternative Pennsylvania Mercury Rule that would require controls on oxidized mercury alone would result in essentially the same reduction in mercury deposition within Pennsylvanian as would the proposed Pennsylvania Mercury Rule.

1.1 Description of sections of report

Section 1.0 of this report contains an introduction, and Section 2.0 discusses the background, including a brief description of the proposed Pennsylvania Mercury Rule and the USEPA's CAMR. Section 3.0 discusses mercury chemistry, and Section 4.0 describes the modeling that ENVIRON conducted to evaluate the Pennsylvania Mercury Rule. Section 5.0 contains a discussion of other issues that were raised in the hearings for the Pennsylvania Mercury Rule and Section 6.0 summarizes the conclusions of this report. References are contained in Section 7.0.

2.0 BACKGROUND

This section contains some background that supports the discussion in the balance of the paper. In particular, it contains brief descriptions of the Pennsylvania Mercury Rule, CAMR, and describes sources of mercury in the environment. It also briefly discusses the distribution of global mercury emissions.

2.1 Description and contrast of Federal Rule and Pennsylvania Rule

The USEPA promulgated the Clean Air Interstate Rule (CAIR) in March 2005. CAIR requires reductions in emissions of oxides of nitrogen and sulfur from coal-fired EGUs in the eastern United States. Regional reductions in emissions of these pollutants were mandated in order to reduce regional transport of oxides of nitrogen and sulfur and resulting ozone and fine particulates exceedances of ambient air quality standards east of the Mississippi. As a benefit of the installation of pollution control equipment that will be required by CAIR, reductions of mercury emissions will also result. As described below, CAMR was developed with recognition of the mercury emissions reductions that will result from CAIR, and requires further reductions of mercury emissions from coal-fired EGUs in the United States.

CAMR addresses mercury emissions under the New Source Performance Standards provisions of the Clean Air Act, rather than under the Hazardous Air Pollutants section. Pennsylvania has stated in the preamble to the Pennsylvania Mercury Rule that it has a concern that by allowing emissions trading cost-effectively to reduce mercury emissions, mercury hot-spots could potentially form around those power plants that traded to meet their emissions caps, rather than reducing emissions at that plant.

2.1.1 Clean Air Mercury Rule

CAMR regulates mercury emissions from coal-fired EGUs. The rule creates a market-based cap-and-trade program that will permanently cap utility mercury emissions in two phases. The first phase of the rule sets a cap of 38 tons per year and due to incentives created by the cap and trade program USEPA projects that emissions will decrease from 48 tons (the total national mercury emissions from power plants in 1999) to 31 tons beginning in 2010. Mercury emissions from power plants will continue to decline thereafter until they are reduced to the second phase cap of 15 tons when the program is fully implemented. Upon full implementation, CAMR will reduce the emissions from coal-fired EGUs by nearly 70% from the 1999 baseline described above. As a cap-and-trade program, CAMR will result in nationwide reductions in mercury emissions, and reductions in emissions from some sources may be greater than from others.

2.1.2 Pennsylvania Mercury Rule

The proposed Pennsylvania Mercury Rule imposes both emissions standards and annual emissions limits on mercury emissions from EGUs. Both types of controls apply with Phase I beginning in 2010 and Phase II beginning in 2015. However, because the annual emission limits are generally tighter than the emission standards, the annual limits drive the necessary technology (URS 2006).

With respect to the emission standards, in Phase I, pulverized coal-fired EGUs must control total mercury emissions by 80% as measured from mercury content of the coal, or achieve an emission rate of 0.024 lbs per GWh. In Phase II, these units must meet 90% control efficiency or 0.012 lbs per GWh. The preamble explains that these reductions will likely be obtained through the use of certain presumptive technologies that may already be installed or are anticipated to be installed to comply with CAIR. The proposed rule provides that units burning 100% bituminous coal with ESP and wet scrubber will presumptively meet the 80% control standard, and units using those controls plus SCR will presumptively be able to meet the 90% standard.

Each EGU must also comply with an annual emission limit by holding non-tradable allowances. DEP proposes to allocate these allowances based on the EPA budget of mercury emission allowances granted under CAMR. In addition, the reduced Phase II budget would be effective in 2015 under the proposal rather than in 2018 under CAMR.

2.2 Sources of Mercury in the Environment

The study of mercury in the environment has been active for more than 20 years. Based on a seminal study that measured tropospheric mercury across world oceans, Slemr et al. (1981) estimates that approximately 5,500 tons of mercury are present in the earth's troposphere.

As is further discussed in Section 3 of this report, mercury in the atmosphere can be primarily found in three states: elemental, oxidized and particle-bound. Most mercury in the atmosphere is found in the elemental state because oxidized and particle-bound mercury have comparatively shorter atmospheric residence times. The properties of elemental mercury, particularly its volatility and low reactivity, result in its status as a global pollutant. Elemental mercury's special properties result in two phenomena: 1) it can be readily reemitted to the air once deposited to surfaces, and 2) it exists in the atmosphere predominantly in the vapor phase (Schroeder 1988). These two properties, and elemental mercury's relative inertness that results in an atmospheric residence time of the order of 1 yr (Slemr et al, 1981; Lindqvist and Rodhe, 1985), support the concept of mercury as a "global pollutant." This residence time is quite long when compared with other metals, since such other metals are typically preferentially associated with airborne particulate matter that deposit relatively rapidly, on the order of days to weeks. This long residence time results in potential transport of elemental mercury emissions around the world tens of times during its atmospheric lifetime. Atmospheric mercury has both anthropogenic and natural sources. These are discussed below.

2.2.1 Natural Sources of Mercury in the Environment

Mercury is released into the atmosphere from a variety of natural sources. The natural sources include volcanoes, geothermal sources, natural fires, soils, forests, lakes and open oceans which account for approximately 2,000 tons per year (Lin, et al., 1999). Mercury from volcanoes and geothermal sources represent primary mercury emissions, whereas emissions from fires, forests, lakes and open oceans largely result from re-emitted mercury as a part of the global mercury cycle. Elevated levels of mercury in waters far from the anthropogenic emission sources have also been documented indicating that atmospheric deposition is an important source of contamination (Lin, et al., 1999).

Episodic emissions of mercury from volcanic eruptions result in substantial injections of mercury into the atmosphere. Ice cores taken from a glacier in Wyoming show spikes in mercury deposition in excess of 10 times the annual deposition in the years following volcanic eruptions, such as Mount St. Helens (Shuster, et. al., 2002). The many years of increased deposition after a discrete release of mercury is the result of the very long residence time that elemental mercury has in the atmosphere.

2.2.2 Anthropogenic Sources of Mercury in the Environment

Anthropogenic mercury emissions are the mobilization or release of mercury by human activities. Anthropogenic mercury emissions can be divided into area and point sources. Anthropogenic area sources of mercury emissions are typically small and numerous and usually cannot be readily located geographically. In 1997, USEPA published a comprehensive inventory of sources of mercury emission in the United States (USEPA, 1997). At that time, the United States' (US) inventory of anthropogenic mercury emissions into the atmosphere was estimated to be 158 tons annually. Total world-wide anthropogenic mercury emission into the environment during that same time period was thought to be on the order of 4,000 tons per year (Lin et al., 1999).

Of the total US emissions, approximately 87 percent was determined to be from combustion point sources, 10 percent is from manufacturing point sources, 2 percent from area sources, and 1 percent is from miscellaneous sources. Four specific source categories accounted for approximately 80 percent of the total anthropogenic emissions in the United States — coal-fired utility boilers (33 percent), municipal waste combustion (19 percent), commercial/industrial boilers (18 percent), and medical waste incinerators (10 percent) (USEPA, 1997). Regulation since that time has decreased emissions from municipal waste combustors and medical waste incinerators, leaving coal-fired utility boilers and commercial/industrial boilers as the remaining largest point sources of mercury. For these two sources, the mercury is present as a trace contaminant in the fuel or feedstock. Because of its relatively low boiling point, mercury is volatilized during high temperature operations and discharged to the atmosphere with the exhaust gas.

2.2.3 Estimates of global distribution of Hg emissions

Pacyna and Pacyna (2002) estimate that in 1995, the Asian countries contributed about 56% to the global emissions of mercury to the atmosphere and that Europe and North America contributed less than 25%. Jaffee (2005) believes that the mercury emissions from Asia are substantially underestimated. The rapid industrialization of Asia, in particular, China and India, is leading to increasing emissions of mercury from coal-fired power plants in those nations. The calculated total amount of anthropogenic mercury emissions of China in 1995 was approximately 235 tons, which accounts for about 5% of estimated total global anthropogenic discharge of 4,400 tons in the same period. From 1978 to 1995, total coal consumption increased fourfold. Based on these data it was estimated that the mercury emissions would increase at a rate of 5% a year, and the calculated emissions in China for 2000 was 300 tons (Zhang, 2002). The continuing increasing use of coal to fire power plants in China and India will result in continuing increases in global mercury emissions, unless regulations are introduced to minimize mercury emissions in those two countries.

2.3 Mercury is a global pollutant

Mercury is ubiquitous in the global atmosphere. The global background airborne concentration of mercury is relatively stable throughout the northern and southern hemispheres respectively (Slemr, 1981), with average concentrations of 1.56 ng/m^3 in the northern hemisphere and 1.05-0.22 ng/m^3 in the southern hemisphere. The majority (>95%) of mercury in the Earth's atmosphere is gaseous elemental mercury, which compared to ionic forms of mercury is relatively inert, and exists almost exclusively in the gas phase (Schroeder and Munthe, 1998). Concentrations of oxidized mercury were generally below detection limits of 0.00088 ng/m^3 and never exceeded 0.005 ng/m.^{3} Concentrations of particle-bound mercury ranged from below detection limits to close to 0.03 ng/m^3, showing a distribution similar to that of other background measurements of mercury.

3.0 ATMOSPHERIC BEHAVIOR OF MERCURY

Atmospheric mercury is present in the environment in three distinct forms (Schroeder and Munthe, 1998; Lin and Pehkonen, 1999), as described below. Under most circumstances the predominant form is elemental mercury, which is believed to have an atmospheric lifetime of about one year (Slemr, 1981; Lindquist and Rhode, 1985). The oxidation state and form of mercury in the atmosphere strongly influences its residence time in the atmosphere. The mercury forms described below can be transformed as a result of atmospheric chemistry. A discussion of the relevant atmospheric chemistry is contained in this section.

3.1 Elemental mercury

Elemental mercury (also referred to as "mercury zero" or "Hg") is present in the atmosphere as a gas. It is a liquid at room temperature with a vapor pressure of 0.18 Pa (Schroeder and Munthe, 1998). The vapor pressure of elemental mercury (~20 parts per million at room temperature) far exceeds the typical background air concentrations of elemental mercury (Lin and Pehkonen, 1999). Elemental mercury is very insoluble in water and has low tendency to dissolve in atmospheric water. The water solubility of elemental mercury is 5×10^{-5} g/l and the Henry constant is 0.0014 M/atm at room temperature (Schroeder and Munthe, 1998).

Because elemental mercury reacts slowly with atmospheric oxidants and tends not to dissolve in water, emissions of elemental mercury tend to remain in the atmosphere for about a year and can be transported over very long distances (around the globe several times). Removal of elemental mercury by dry and wet deposition to the earth's surface is slow because elemental mercury has low affinity for water. Elemental mercury that is deposited to the earth's surface may subsequently be re-emitted in the gaseous phase because elemental mercury is volatile. Deposition depends primarily on oxidation to oxidized mercury over a large period of time.

3.2 Oxidized mercury

The group of compounds referred to as oxidized mercury is sometimes referred to as "Mercury Two" "Hg^2," "reactive gaseous mercury" or "Ionic Mercury". Oxidized mercury is an operational term for atmospheric mercury compounds that are gasses, water soluble and chemically reactive. Oxidized mercury includes compounds such as $HgCl_2$ (Schroeder and Munthe, 1998) where mercury has a formal oxidation state of plus 2, hence the name "Mercury Two." Oxidized mercury compounds are present in the gas phase at low concentrations. For example, $HgCl_2$ has a vapor pressure of 0.009 Pa at room temperature (Schroeder and Munthe, 1998) which is equivalent to 0.09 ppm. Oxidized mercury dissolves readily in water and therefore is efficiently removed from the atmosphere by wet deposition (dissolving in rain) and dry deposition (dissolving in plant leaf tissues or surface water). The relative importance of dry versus wet deposition of oxidized mercury will depend upon rainfall and ground cover in a particular area. Emissions of oxidized mercury are likely to remain in the atmosphere for no more than a few days and be transported no more than a few hundred miles because removal by wet and dry deposition is relatively efficient.

3.3 Particle-bound mercury

Particle-bound mercury comprises mercury compounds that are bound to aerosols or particulate matter. Particle-bound mercury is likely to be in a divalent chemical form (the same as oxidized mercury) but differs from oxidized mercury by being much less volatile. For example, mercury oxide (HgO) has very low vapor pressure and will be present in the atmosphere as a solid, most likely attached to a host aerosol particle (Schroeder and Munthe, 1998). Particle-bound mercury also deposits relatively efficiently; its deposition rate is a function of particle size and meteorological conditions.

3.4 Chemical Reactions of Mercury in the Environment

The most important atmospheric chemical reactions for mercury are oxidation and reduction reactions that convert mercury between its elemental and oxidized forms. The significance of these reactions is that elemental mercury is deposited slowly and transports over great distances, whereas oxidized mercury is deposited more rapidly. Oxidation reactions convert elemental mercury to oxidized mercury (and/or particle-bound mercury) whereas reduction reactions convert oxidized mercury to elemental mercury. Both gas-phase and aqueous phase reactions are important for atmospheric mercury (Schroeder and Munthe, 1998; Lin and Pehkonen, 1999; Bullock, 2006).

Gas-phase reactions in the atmosphere slowly oxidize elemental mercury to oxidized mercury. The important oxidants are thought to be ozone (O_3), hydroxyl radical (OH) and chlorine (Cl_2) (Lin and Pehkonen, 1999), although the importance of OH has been challenged (Calvert and Lindberg, 2005), as discussed later in this report. Ozone and OH are prevalent throughout the atmosphere, providing a ubiquitous pathway for converting elemental mercury to oxidized mercury. However, the reaction between elemental mercury and O_3 is slow, consistent with elemental mercury having an atmospheric lifetime of about 1 year. Chlorine reactions can accelerate the oxidation of elemental mercury to oxidized mercury and may become important in maritime areas and near sources of chlorine emissions.

Aqueous-phase reactions in the atmosphere can both oxidize elemental mercury to oxidized mercury and reduce oxidized mercury to elemental mercury. A schematic diagram of aqueous-phase mercury reactions is shown in Figure 3-1 (from Bullock, 2006). Aqueous-phase reactions that can oxidize dissolved elemental mercury to oxidized mercury involve dissolved O_3, OH, and chlorine-containing species (OCl^- and HOCl). Reactions that can reduce oxidized mercury to elemental mercury involve dissolved sulfur species (i.e., dissolved forms of SO_2), hydroperoxy radical (HO_2) and photolysis of $Hg(OH)_2$.

Mercury can form many stable complexes with organic (carbon-containing) compounds. Methyl mercury is a toxic, organic mercury compound that is fairly soluble in water. Dimethyl mercury, another organic mercury compound, is much less soluble. Inorganic mercury can be methylated by microorganisms indigenous to soils, sediments, fresh water, and salt water, to form organic mercury. Almost all of the mercury found in animal tissues is in the form of methyl mercury, which efficiently bio-concentrates in fish.

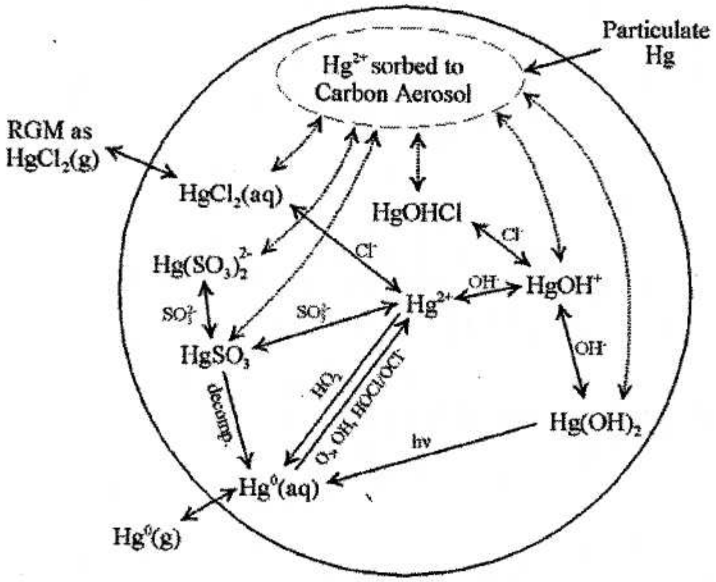


Figure 3-1 – Reactions of mercury within cloud and rain droplets as modeled by CMAQ (Bullock, 2006).

3.5 Conceptual Model of Mercury Emissions from Power Plants

The current knowledge of the atmospheric chemical and physical properties of mercury compounds may be synthesized in the following conceptual model of the fate of power plant mercury emissions:

- Emissions of elemental mercury deposit slowly and react slowly – they will tend to have an atmospheric lifetime of about 1 year, meaning that they can circle the globe many times before depositing far from the original source. Emissions of elemental mercury will mostly enter a global pool of atmospheric elemental mercury.

- Emissions of oxidized mercury and particle-bound mercury deposit within a few days and therefore mostly will be deposited within a few hundred miles downwind of the source. Oxidized mercury is also slowly converted to elemental mercury and the small fraction that is converted to elemental mercury before depositing as oxidized mercury will enter the global pool of elemental mercury.
- Emissions of particle-bound mercury are not converted to other forms of mercury and will be removed by deposition.

4.0 EVALUATION OF DEPOSITION IN PENNSYLVANIA WITH ALTERNATIVE CONTROL STRATEGIES

As discussed earlier in this report, the state of mercury when it is emitted from EGUs substantially affects its fate and transport after emissions. Elemental mercury is not water soluble and typically enters the global pool of mercury. As a result, the great majority of elemental mercury emitted from EGUs is not deposited near the emission source. Oxidized and particle-bound mercury is typically deposited within a few days of emission, however, particle-bound mercury is already being controlled in Pennsylvania. As shown from modeling discussed in this section, a portion of the oxidized and particle-bound mercury emitted from EGUs in Pennsylvania is deposited somewhere in Pennsylvania.

Because there is such a substantial difference in the behavior of mercury based on the state, ENVIRON evaluated alternative control scenarios for mercury based on the state of the mercury. In other words, rather than treating all mercury as being equal for the purposes of deposition, which it is not, the modeling scenarios were conducted to understand how a control scenario can be designed to minimize the mercury emissions that had the potential to deposit in Pennsylvania, while not requiring the control of mercury that would not impact deposition in Pennsylvania.

ENVIRON's modeling effort utilized models and databases developed for USEPA's CAMR incorporating some recent updates. To understand the magnitude of the change in mercury deposition under various potential mercury control strategies, ENVIRON prepared a "Pennsylvania Mercury Rule" run where it was assumed that elemental and oxidized mercury emissions were controlled to 90%, with no further control on the particle-bound mercury. While the Pennsylvania Mercury Rule will in fact, require greater control as a result of the annual emissions cap, this level of control was chosen as it is the stated control goal of the Pennsylvania Mercury Rule. The Pennsylvania Mercury Rule run will allow a comparison of potential control strategies with the control level sought in the Pennsylvania Mercury Rule. The methodology used to conduct that analysis is presented below. First a description of the methods used to estimate emissions under the scenarios is presented, and second, a description of the modeling that was conducted is provided. Finally, the results are presented.

Emissions from Pennsylvania are changed according to the potential scenarios modeled, whereas mercury emissions in the balance of the nation were assumed to be those estimated for the year 2020 under CAMR Option 1 as described below.

4.1 Models and Databases

Mercury modeling was conducted using version 4.5.1 of the Community Multiscale Air Quality (CMAQ v4.5.1) model. Version 4.5.1 is the first public release of CMAQ to include mercury modeling capabilities. USEPA developed the CAMR rule using an earlier version of CMAQ. Updates to CMAQ v4.5.1 from the CAMR version of the model are described in Appendix A. Appendix A also shows a comparison of estimated mercury deposition using the CAMR model and the CMAQ v4.5.1 model that was used for this study. The model configuration used in this study was the same as that used by the USEPA to support the development of CAMR; the CAMR modeling domain includes the entire continental US at 36-km grid resolution for all of calendar year 2001.

4.2 Mercury Emissions Inventories

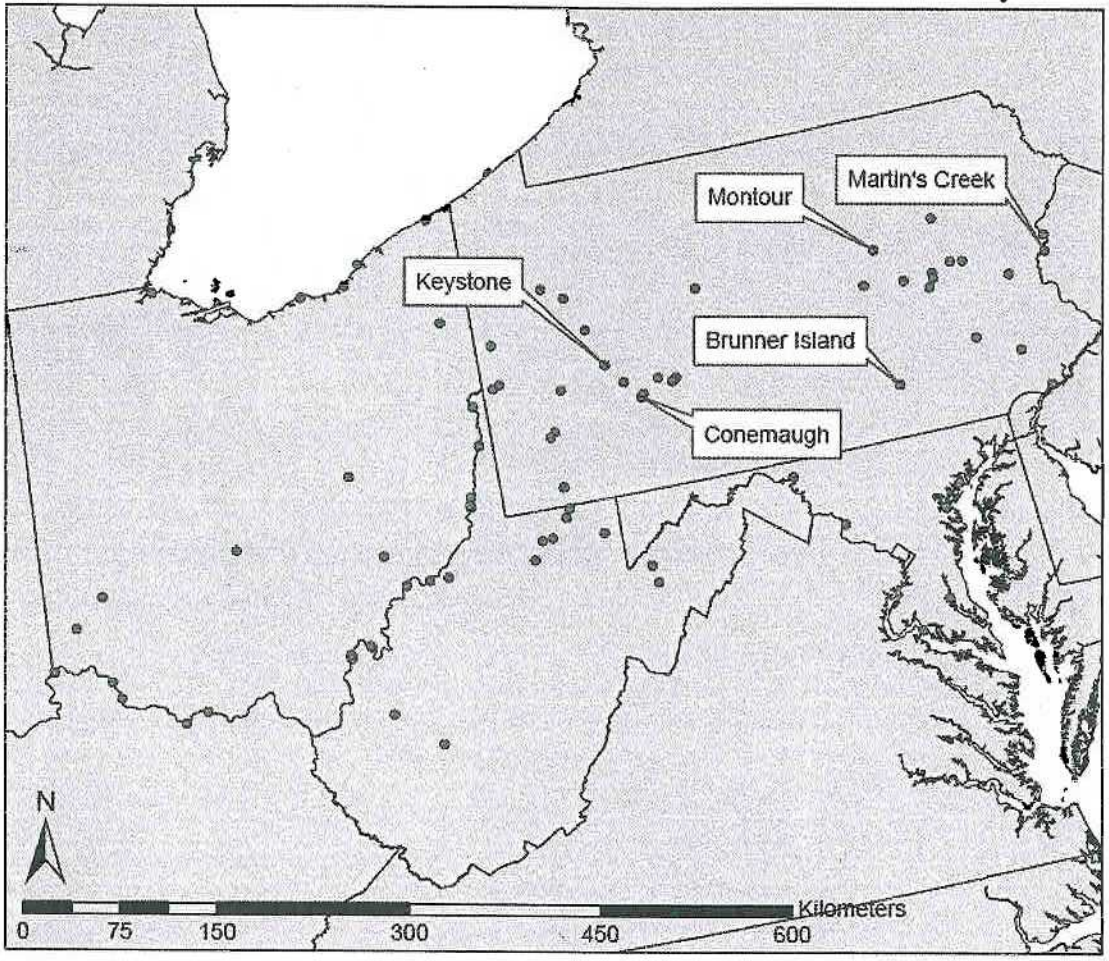
In support of CAMR, the USEPA developed several inventories of mercury emissions from EGUs in the United States. USEPA developed the CAMR emissions inventories from the information contained in the emissions inventories that USEPA had developed for CAIR. The 1999 National Emissions Inventory was used to provide base data for the 2001 CAIR/CAMR inventory. USEPA used the Integrated Planning Model (IPM) to predict where increases in electrical generation would occur, and with what type of facility, and also used IPM to predict where controls would be most efficient under both CAIR and CAMR to predict mercury emissions for the post-CAMR inventory. The year 2020 was chosen by USEPA to represent the post-CAMR year, and thus is also used in this study for emissions outside of Pennsylvania.

The USEPA 2001 EGU inventory for oxidized and elemental mercury in Pennsylvania is shown in Table 4-1. The emission sources are fairly well distributed in Pennsylvania, as shown in Figure 4-1. Facilities that are owned or partly owned by PPL are labeled in this Figure. Figure 4-1 also shows the locations of some EGUs in neighboring states that emit mercury. Table 4-1 divides the facilities into those with individual units greater than 250 Mw, and those with units smaller than 250 Mw. This emissions inventory was used to prepare Pennsylvania emission inventories for the scenarios that were modeled. As can be seen, nearly 80% of Pennsylvania's EGU mercury emissions result from the sources that have EGUs with a capacity of 250 Mw or greater. In addition, approximately two-thirds of the EGU mercury emissions in Pennsylvania is in the oxidized form for the baseline year. As will be shown below, the control of the oxidized form of mercury within Pennsylvania will result in essentially all of the deposition reductions that can be achieved by controlling total mercury emissions in Pennsylvania.

Table 4-1 – 2001 Annual Mercury Emissions from CAMR Modeling (tons/year)

	Unit [size (MW)]							
Name	1	2	3	4	5	Hg(0)	Hg(2)	Total Hg
Conemaugh	850	850				0.228	0.019	0.247
Keystone	832	832				0.238	0.631	0.87
BruceMansfield	805	785	781			0.316	0.173	0.489
Montour	729	744				0.157	0.416	0.572
BrunnerIsland	720	370	314			0.057	0.148	0.207
HomerCity	601	607	650			0.238	0.632	0.87
Cheswick	550					0.03	0.081	0.111
Seward	520					0.009	0.014	0.023
Hatfield'sFerry	490	490	490			0.053	0.141	0.195
Eddystone	279	302	380	380		0.021	0.002	0.022
Mitchell(PA)	275					0.014	0.001	0.015
Subtotal Large Units (>250 Mw)						1.36	2.258	3.621
				% of Total		81%	76%	78%
Armstrong	167	168				0.039	0.105	0.144
Portland	158	238				0.017	0.045	0.062
Cromby Generating Station	144	201				0.0005	0.0003	0.0009
Martins Creek	140	140				0.007	0.018	0.024
Shawville	122	125	171	171		0.119	0.316	0.437
Colver Power Project	116					0.01	0.01	0.02
Northampton Generating Co, L.P.	102					0.0003	0.0002	0.0005
St. Nicholas Cogeneration Project	101					0.0002	0.0001	0.0003
New Castle	98	98	134			0.027	0.071	0.099
Elrama	97	97	109	171		0.027	0.002	0.029
Cambria Co Gen	87					0.01	0.01	0.02
Panther Creek Energy Facility	83					0.0001	0.0001	0.0002
Scrubgrass Generating Company L.P.	82					0.0003	0.0002	0.0004
John B. Rich Memorial Power Station	80					0.0002	0.0001	0.0003
Titus	79	81	81			0.01	0.026	0.036
Ebensburg Power Company	51					0.0002	0.0001	0.0003
Kline Township Cogen Facility	50					0.0001	0.0001	0.0002
Hunlock Power Station	48					0.007	0.018	0.024
Wheelabrator Frackville Energy Co	43					0.0001	0.0001	0.0002
Foster Wheeler Mt. Carmel Inc	40					0.0001	0.0001	0.0002
Sunbury	38	38	38	38	83	0.031	0.08	0.112
Piney Creek Project	32					0.0001	0.00004	0.0001
AESBV Partners Beaver Valley	29	98				0.014	0.001	0.015
Subtotal Small Units (<250Mw)						0.32	0.703	1.026
Pennsylvania **Total**						**1.68**	**2.96**	4.647

Figure 4-1 - Location of EGUs in the 2001 CAMR Emissions Inventory



4.3 Alternative Emissions Scenario Modeling

As noted above, the USEPA used 2020 as the year to evaluate post-CAMR benefits. To allow consistency with this time frame, and to use the databases prepared by the USEPA, 2020 was chosen as the post-rule implementation year for modeling the alternative emissions scenarios. To evaluate what benefit alternative control scenarios would provide in post-CAMR implementation (2018 and beyond), ENVIRON conducted 2020 future year CMAQ simulations shown in Table 4-2, below:

Table 4-2 – EGU Emission Control Scenarios Modeled (% control)

	Oxidized Mercury		Elemental Mercury	
Run Number	>250 Mw	1-250 Mw	>250 Mw	1-250 Mw
1	90%	90%	90%	90%
2	90%	50%	---	---
3	90%	90%	---	---

No further control for the particle-bound mercury was assumed here, as particulate emissions are already well controlled in Pennsylvania EGUs, as a result of the existence of particulate control on all coal-fired units (URS, 2006). The emission inventories, and the methods used to create the emissions inventories for each scenario can be found in Appendix B.

Table 4-3 shows the results of the modeling. By modeling 90% reductions in both elemental and oxidized mercury emissions from all EGUs in Pennsylvania, Run 1 is meant to represent predicted deposition in Pennsylvania in 2020 with achievement of the stated goal of the Pennsylvania Mercury Rule. As noted earlier in this report, the mercury deposition model is run on a 36 km resolution grid. The deposition can be evaluated on a grid-by-grid basis to evaluate the maximum grid change between scenarios. The maximum change of any grid cell for the scenario comparison is also shown in Table 4-3. The details of the changes for each grid cell in Pennsylvania for each scenario comparison are shown in Appendix C.

Table 4-3 – Results of Alternative Emissions Control Scenarios and Comparison Relative to Run 1

	Anthropogenic Hg emissions in PA [tons/yr]	Hg deposited in PA [tons/yr]	Change in total deposition [%]	Max Grid Cell Change [%]
Run 1 – Proposed Mercury Rule	3.63	3.389	N/A	N/A
Run 2	5.31	3.471	2.42%	19.4%[2]
Run 3	5.05	3.399	0.28%	1.12%

By comparing the emissions inventories and the resultant estimated deposition, the amount of each type of mercury remaining in Pennsylvania can be estimated. This evaluation is shown in Appendix D of this report. As a result of the evaluation, it is clear that less than 0.75% of the EGU-emitted elemental mercury is deposited in Pennsylvania, whereas over one-quarter of the oxidized mercury emitted from Pennsylvania's EGUs is deposited in Pennsylvania. This is consistent with the atmospheric chemistry discussed earlier in this report, and allows the estimation of the impact of controls on smaller units at different levels than what was modeled in this report.

A comparison of the percent difference in deposition among the various runs reveals the benefits of differentially controlling oxidized and elemental mercury. The comparison is shown in Table 4-3. The most telling comparison is Run 1 compared to Run 3. In these two runs, the only difference is that the elemental mercury from all EGUs in the state is reduced by 90% in Run 1

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[2] This represents the greatest difference for any gird cell in the state. The second greatest difference was just over 10%, and all other grid cell differences were less than 10%.

and is not reduced in Run 3. The predicted difference in total deposition in Pennsylvania is less than 0.3%, clearly showing that the control of elemental mercury produces essentially no benefit for Pennsylvania. Even in the grid cell that shows the maximum change in deposition for this case, the maximum change is slightly over 1%. In fact, control of elemental mercury could be counterproductive to the extent that control technologies are used that oxidize elemental mercury in order to then capture it (URS, 2006). Because the oxidized form of mercury is over 40 times more likely to deposit in Pennsylvania than is the elemental form, any control technology that increases, even slightly, the oxidized form of mercury while reducing the elemental form of mercury may result in additional deposition in Pennsylvania, rather than a reduction in deposition in Pennsylvania.

A comparison in Table 4-3 of the differences in predicted deposition of total mercury with Run 2 [50% control on the oxidized mercury emissions from the small EGU's (the large EGUs being modeled at 90% reductions in all cases)] compared to Run 1 (which assumes 90% reductions in both oxidized and elemental mercury from all uncontrolled EGUs in Pennsylvania) shows how much difference in deposition of mercury is obtained by controlling oxidized mercury emissions from the small EGUs (i.e under 250 MW). The average change in deposition within Pennsylvania is slightly over two percent, if the smaller uncontrolled EGUs in Pennsylvania are controlled at a 50% rate.

4.4 Conclusions

As discussed above, the differences between the behavior of elemental and oxidized mercury emissions from EGUs indicate that control strategies should consider the types of mercury being emitted from the EGUs. ENVIRON's studies show that less than 0.75% of the elemental mercury being emitted from Pennsylvania's EGUs is deposited in Pennsylvania. The bulk of the elemental mercury emitted from Pennsylvania's EGUs enter the global pool of mercury. This behavior lends itself well to control by emissions trading schemes. Approximately one-quarter of the oxidized mercury released from Pennsylvania's EGUs does deposit in Pennsylvania. Control of this species of mercury will reduce mercury deposition in Pennsylvania. Therefore, an emission control scheme that focuses on the type of mercury emitted will result in more effective control of mercury deposition in Pennsylvania.

Because oxidized mercury is over 40 times more likely to deposit in Pennsylvania than is the elemental version, control technologies that increase, even slightly, oxidized mercury emissions while lowering overall mercury emissions, could have the result of increasing mercury deposition in Pennsylvania, rather than lowering it, as would be intended.

5.0 EVALUATION OF OTHER INFORMATION ON MERCURY DEPOSITION

A discussion follows regarding some of the uncertainties in the scientific literature on mercury oxidation pathways and mercury disposition and how these uncertainties might impact the results of ENVIRON's Pennsylvania study. The evaluation conducted in this report is based on a body of science that has been developing for the past 20 years. This report is based on the current consensus of the scientific community. New information continues to emerge, and some examples are discussed below. Our current understanding of the science is consistent with real-world data. The full implications of the new scientific information, if any, can not be determined until this information has been similarly reconciled with, and is determined to be consistent with real-world data.

5.1 Uncertainty in Atmospheric Chemistry

ENVIRON has based its modeling on USEPA's modeling, which incorporates assumptions about atmospheric chemistry. Researchers have studied many of the reactions that are believed to be important to mercury chemistry in the atmosphere and then synthesized this knowledge into chemical mechanisms suitable for atmospheric modeling (e.g., Bullock, 2006). Nevertheless, there are uncertainties in the chemical mechanisms for atmospheric mercury as illustrated by two recent publications. In 2005, Calvert and Lindberg argued that some of the important gas-phase oxidation pathways for elemental mercury may not be understood, suggesting that oxidation of elemental mercury to oxidized mercury could be slower than currently believed. In 2006, Lohman et al. argued that the known reduction reactions for oxidized mercury to elemental mercury are unable to explain what happens in power plant plumes in the southeastern U.S. and therefore that the reduction of oxidized mercury to elemental mercury could be faster than currently believed.

The implications of these two apparently divergent papers have not yet been incorporated by the mercury modeling community. The incorporation of new information into the atmospheric chemical models of mercury will require an understanding of how changes in parts of the atmospheric chemical models impact the overall chemical models as a whole. The models will then need to be reevaluated against ambient data for mercury concentrations and deposition. Additional changes to the chemical mechanisms may be needed to reconcile new reaction data with ambient data. In other words, overall atmospheric data (and models) constrain how the chemical mechanisms can be changed, making it difficult to anticipate how current uncertainties in chemical mechanisms ultimately may change our understanding of mercury chemistry in the atmosphere and the results of mercury deposition modeling studies.

5.2 Evaluation of Steubenville Study

A USEPA-sponsored mercury sampling and analysis project began in Steubenville, Ohio, in 2002. While there have been at least three presentations describing preliminary results of this study, as of June 2006, there have been no peer-reviewed publications of these data, nor have any written reports been made available by the Steubenville investigators regarding data, methods, analysis, and findings.

The Steubenville study uses a source receptor methodology to estimate the deposition from "coal combustion sources". Furthermore, the investigators classify the sources not as "local", but rather, "local/regional". Data from the Beijing October 2005 presentation is shown in Table 5-1.

Table 5-1 Comparison of Wet Deposition from Steubenville Study and CMAQ Runs for the Steubenville Grid Cell

Study/Year	Wet Deposition ($\mu g/m^2$)	% from Coal-Combustion Sources
CMAQ 4.5.1 2001	12.0	43%*
Keeler 2002	13.1	60%-73%
Keeler 2003	18	59%-62%

*From Keeler's Beijing Presentation; no independent verification conducted

For the measured vs. estimated wet deposition, the difference between the two years measured in the Steubenville study is nearly 5 $\mu g/m^2$. CMAQ also represented a single meteorological year. The difference between the CMAQ value for a single year, and the average of the two years in the Steubenville study is less than the difference between the two years of Steubenville study. Recognizing that CMAQ uses a wholly different method, different meteorological years, and different emissions data, this is very good agreement between the two methods.

As to the difference between the coal-derived mercury between the two studies, the CMAQ results do not represent all coal-derived mercury. Rather, we understand that it represents the fraction of emissions that are derived from coal-fired EGUs. There are other substantial sources of coal combustion near Steubenville. In addition, again, the differences are not substantial given the differences in the approach, meteorological year and data sets. Rather than provide a challenge to the CMAQ results, this evaluation supports the CMAQ results.

6.0 CONCLUSIONS

Mercury is a global pollutant. Elemental mercury, the most common type of mercury in the atmosphere, has an atmospheric residence time of approximately one year. ENVIRON's evaluation shows that less than 1% of the elemental mercury released from Pennsylvania's EGUs is deposited in Pennsylvania, whereas approximately one-quarter of the oxidized mercury released from Pennsylvania's EGUs is deposited in Pennsylvania. The majority of mercury deposition in Pennsylvania is from out-of state and, indeed, off-shore sources. As a result, when considering additional controls in Pennsylvania, only controls on oxidized mercury emitted from EGUs in Pennsylvania will result in meaningful reductions of mercury deposition in Pennsylvania. The difference in total deposition in Pennsylvania from controlling 90% of oxidized mercury from all Pennsylvania EGUs versus 90% of total mercury (oxidized and elemental) from those same sources is less than 0.3% and the maximum grid cell difference is 1.12%. The data included in this report also show that reducing the stringency of controls on oxidized mercury only for EGUs less than 250 MW in size (compared to a 90% control requirement), generally has a modest impact on mercury deposition in Pennsylvania. Clearly, it is control of oxidized mercury that is most beneficial for Pennsylvania. Furthermore, as the most common and technologically proven type of elemental mercury control actually slightly increases the amount of oxidized mercury emitted from an EGU, controlling elemental mercury has the potential to result in more, not less mercury deposition in Pennsylvania.

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APPENDIX A

CMAQ V4.5.1: CHANGES TO MODEL AND COMPARISON WITH CAMR MODELING

Mercury modeling in this report was conducted using version 4.5.1 of the Community Multiscale Air Quality (CMAQ v4.5.1) model. Version 4.5.1 is the first public release of CMAQ to include mercury modeling capabilities. EPA developed the CAMR rule using an earlier version of CMAQ. A comparison of estimated mercury deposition using the CAMR model and the CMAQ v4.5.1 model that was used for this study is presented in this appendix. The model configuration used in this study was the same as that used by the EPA to support the development of CAMR. The CAMR modeling domain includes all of the continental US at 36-km grid resolution for all of calendar year 2001. Updates to CMAQ v4.5.1 from the CAMR version of the model are as follows:

- Dry deposition of elemental mercury was added.
- Elemental mercury reaction with H_2O_2 assumes the formation of 100% oxidized mercury rather than 100% particle-bound mercury.
- Elemental mercury reaction with O_3 assumes the formation of 50% oxidized mercury and 50% particle-bound mercury rather than 100% particle-bound mercury.
- Elemental mercury reaction with OH assumes the formation of 50% oxidized mercury and 50% particle-bound mercury rather than 100% particle-bound mercury.
- The rate constant for the reaction of elemental mercury and OH was slightly lowered.

Meteorological and related input data for CMAQ are prepared using a pre-processor called MCIP. The CMAQ meteorological inputs available from EPA's CAMR modeling are unsuitable for CMAQ v4.5.1 because they do not include dry deposition rates for elemental mercury. MCIP v3.1 was run to prepare meteorological input data that are suitable for CMAQ v4.5.1.

Since adding deposition of elemental mercury to CMAQ, EPA also has started to include vegetation emissions of elemental mercury in the CMAQ emission inventories. Vegetation emissions of elemental mercury for this study were provided by Bullock[3] and were estimated using a modified version of EPA's model for biogenic VOC emissions (the BEIS model). While adding vegetation emissions, the new version of CMAQ did not remove the vegetation emissions of mercury from the cumulative deposition. In this manner, cumulative deposition is over-

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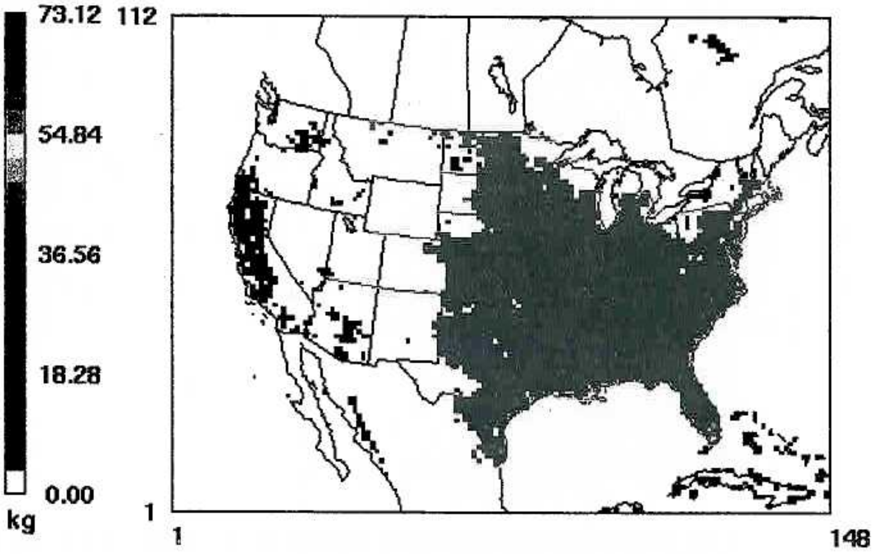
[3] Bullock, R. 2006. Personal communication from Russell Bullock to Greg Yarwood.

estimated slightly. Figure A-1 displays vegetation elemental mercury emissions for 2001. As is shown, there is little vegetative emission in Pennsylvania, so this uncertainty is unlikely to impact the Pennsylvania modeling significantly. The 2001 base case was modeled with CMAQ v4.5.1 to verify the newly-released model's mercury modeling capability and compare it by comparing performance with the results of EPA's CAMR modeling. The model scenario was identical to EPA's CAMR modeling with the following exceptions:

- The newer CMAQ v4.5.1 model was used.
- Meteorological input data were prepared using MCIP v3.1 so as to include deposition of elemental mercury.
- Vegetation emissions of elemental mercury were added.

Figure A-2 compares the annual total mercury deposition predicted by CMAQ v4.5.1 with the corresponding results from EPA's CAMR modeling. The two models predict similar spatial deposition patterns. In general, CMAQ v4.5.1 predicts higher mercury deposition than does EPA's CAMR model due to the inclusion of elemental mercury deposition.



January 1,2001 0:00:00
Min= 0.00 at (36,14), Max= 73.12 at (122,18)

Figure A-1. Annual emissions of elemental mercury from vegetation (kg per 36-km CMAQ grid cell)

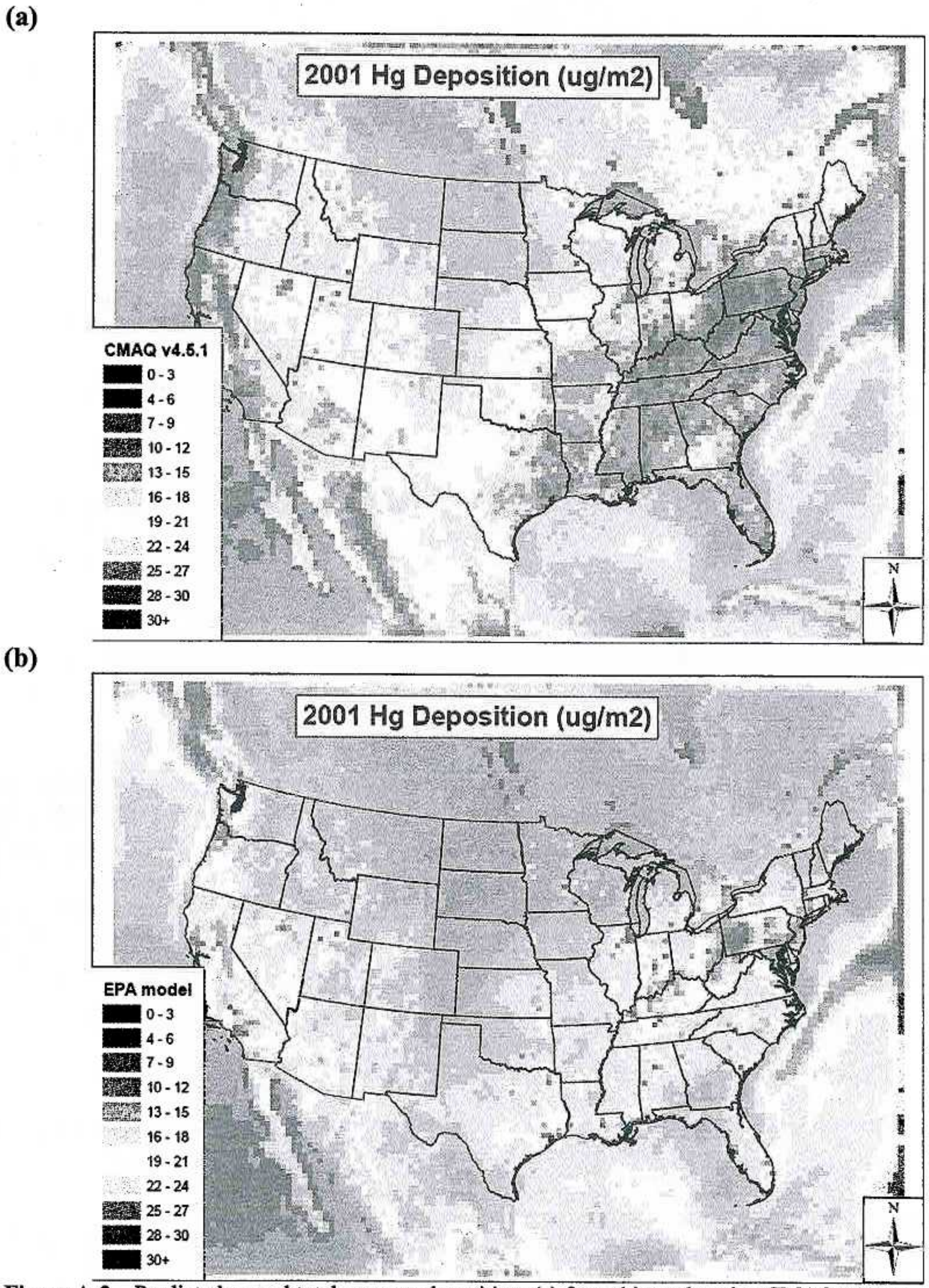


Figure A-2. Predicted annual total mercury deposition: (a) from this study using CMAQ v4.5.1; (b) from EPA's CAMR modeling

APPENDIX B

INVENTORY PREPARATION FOR ALTERNATIVE CONTROL SCENARIOS

There are four emissions inventories that are used for Pennsylvania deposition modeling: the baseline 2001 emissions inventory, and the three alternative future scenarios which incorporate control requirements on different species of mercury for EGUs based on unit size. The CAMR inventories were used as source data for the emissions inventories. The 2001 baseline inventory (with the corrections noted below) was used to prepare the future year inventories. For the future year emissions for all sources of mercury outside of Pennsylvania, the USEPA CAMR Option 1 2020 year estimation inventory was used. The methods used to develop the Pennsylvania inventories are described below.

The baseline CAMR 2001 mercury inventory for Pennsylvania included a relatively high fraction (6%) of particle-bound mercury. When applying its speciation algorithm to the total mercury emissions measured in Pennsylvania, it appears that EPA did not assume that the existing ESPs and baghouses in Pennsylvania would result in the control of the particle-bound mercury for the 2001 inventory, but did assume efficient removal of that species for the 2020 inventories. As the ESPs and baghouses, which remove about 99% of the particle-bound mercury, existed prior to the baseline inventory year of 2001, there should have been very little particle-bound mercury in the baseline inventory. By way of support, the Energy and Environmental Research Center (EERC) notes[4] that their testing of bituminous units with ESPs has shown mercury particulate fractions consistently significantly less than 1%. The revised baseline emissions inventory is shown in Table B-1.

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[4] Telephone conversation: Reid T. Clemmer PPL Services Corp with Michael l. Jones Senior Research Advisor EERC (Energy & Environmental Research Center -University of North Dakota) July 31, 2006.

Table B-1 – 2001 Corrected Baseline

2001 Baseline	**2001 Corrected Baseline**			
Name	Hg(0)	Hg(2)	Hg(P)	Total Hg
Homer City	0.2380	0.6316	0.0002	0.8699
Keystone	0.2380	0.6314	0.0002	0.8695
Montour	0.1566	0.4156	0.0001	0.5723
Bruce Mansfield	0.3157	0.1727	0.0002	0.4886
Shawville	0.1193	0.3165	0.0008	0.4365
Conemaugh	0.2276	0.0192	0.0002	0.2470
Brunner Island	0.0567	0.1484	0.0016	0.2066
Hatfield's Ferry	0.0532	0.1412	0.0002	0.1946
Armstrong	0.0394	0.1046	0.0001	0.1441
Cheswick	0.0305	0.0809	0.0000	0.1114
Sunbury	0.0311	0.0800	0.0008	0.1119
NewCastle	0.0268	0.0712	0.0010	0.0989
Portland	0.0169	0.0449	3.61E-05	0.0618
Titus	0.0098	0.0261	4.67E-05	0.0359
Cambria CoGen	0.0104	0.0098	1.37E-04	0.0203
Elrama	0.0267	0.0023	6.33E-05	0.0290
Seward	0.0094	0.0139	6.01E-05	0.0234
Martins Creek	0.0067	0.0178	3.18E-05	0.0245
Hunlock Power Station	0.0066	0.0176	3.15E-05	0.0243
Colver Power Project	0.0103	0.0096	0.00029	0.0202
Eddystone	0.0205	0.0017	4.87E-05	0.0223
Mitchell(PA)	0.0139	0.0012	2.61E-05	0.0152
AESBV Partners Beaver Valley	0.0138	0.0012	3.27E-05	0.0150
Cromby Generating Station	0.0005	0.0003	5.31E-05	0.00086
Northampton Generating Company L.P.	0.00029	0.00018	1.32E-05	0.00048
Scrubgrass Generating Company L.P.	0.00025	0.00017	8.48E-06	0.00043
St. Nicholas Cogeneration Project	0.00019	0.00012	1.91E-07	0.00031
John B. Rich Memorial Power Station	0.00019	0.00012	1.88E-07	0.00030
Ebensburg Power Company	0.00016	0.00011	5.88E-06	0.00028
Panther Creek Energy Facility	0.00014	8.73E-05	7.04E-06	0.00023
Kline Township Cogen Facility	0.00014	8.6E-05	1.39E-07	0.00022
Wheelabrator Frackville Energy Co Inc	0.00012	7.28E-05	5.88E-06	0.00020
FosterWheeler Mt. Carmel Inc	0.00011	6.78E-05	5.25E-06	0.00018
Piney Creek Project	5.35E-05	3.52E-05	1.92E-06	9.06E-05
Pennsylvania Total	**1.680**	**2.960**	**0.006**	**4.647**

As the particle-bound mercury emissions in Pennsylvania are already efficiently controlled in Pennsylvania, only the elemental and oxidized mercury emissions are discussed and presented in this report. However, the deposition modeling conducted by ENVIRON reflects total mercury deposition. Accordingly, the particulate bound mercury fraction was included in the inventory, although it resulted in a relatively small fraction of the deposition from Pennsylvania sources due to its already high level of control.

The future year inventories presumed differential control on the mercury emissions as a function of three things: 1) EGU size (individual unit, not on a facility basis); 2) whether mercury controls were already installed on the unit for the baseline year (listed as 2001, but actually from the 1999 National Emissions Inventory) and 3) mercury species. Particle-bound mercury was always assumed to be the same as that in the corrected 2001 inventory, except for PPL's Martin's Creek unit, which will be retired in 2007. It was assumed that there were no 2020 emissions of mercury of any type from Martin's Creek. The percent controls for each scenario are listed in Table B-2, and are explained below.

For Scenario 1, which was intended to reflect the proposed Pennsylvania Mercury Rule, it was assumed that oxidized and elemental mercury from Pennsylvania's coal-fired EGUs would be controlled by 90% from the baseline year, for those large units that did not have mercury controls installed as of the baseline year. Although Homer City, Conemaugh, and Bruce Mansfield all reported mercury controls for the baseline years, only the inventory for Conemaugh was consistent with mercury controls. Accordingly, oxidized mercury emissions for all large units, except for Conemaugh were assumed to be controlled at 90%. No other mercury emissions were controlled.

For Scenarios 2 and 3, it was assumed that elemental mercury from all of Pennsylvania's EGUs would be uncontrolled, and that oxidized mercury would be controlled at the 90% level for all EGU units larger than 250 Mw in size for which mercury controls are not already installed. For Scenarios 2, and 3, it was also assumed that the oxidized mercury would be controlled by 50%, and 90%, respectively, for units smaller than 250 Mw in Pennsylvania, where controls were not already installed, and mercury emissions were above a *de minimus* level. The assumed controls on mercury emissions from the baseline shown in Table B-1 is shown in Table B-2.

Table B-2 Percent Reductions from Baseline Emissions Inventories for Pennsylvania EGUs

2001 Baseline	Run 1		Run 2		Run 3	
Name	Hg(2)	Hg(0)	Hg(2)	Hg(0)	Hg(2)	Hg(0)
Homer City	90%	90%	90%	0%	90%	0%
Keystone	90%	90%	90%	0%	90%	0%
Montour	90%	90%	90%	0%	90%	0%
Bruce Mansfield	90%	90%	90%	0%	90%	0%
Shawville	90%	90%	50%	0%	90%	0%
Conemaugh	0%	90%	0%	0%	0%	0%
Brunner Island	90%	90%	90%	0%	90%	0%
Hatfield's Ferry	90%	90%	90%	0%	90%	0%
Armstrong	90%	90%	50%	0%	90%	0%
Cheswick	90%	90%	90%	0%	90%	0%
Sunbury	90%	90%	50%	0%	90%	0%
New Castle	90%	90%	50%	0%	90%	0%
Portland	90%	90%	50%	0%	90%	0%
Titus	90%	90%	50%	0%	90%	0%
Cambria CoGen	0%	0%	0%	0%	0%	0%
Elrama	0%	0%	0%	0%	0%	0%
Seward	90%	90%	90%	0%	90%	0%
Martins Creek	100%	100%	100%	100%	100%	0%
Hunlock Power Station	90%	90%	50%	0%	90%	0%
Colver Power Project	0%	0%	0%	0%	0%	0%
Eddystone	0%	0%	0%	0%	0%	0%
Mitchell(PA)	0%	0%	0%	0%	0%	0%
AESBV Partners Beaver Valley	0%	0%	0%	0%	0%	0%
Cromby Generating Station	0%	0%	0%	0%	0%	0%
Northampton Generating Company L.P.	0%	0%	0%	0%	0%	0%
Scrubgrass Generating Company L.P.	0%	0%	0%	0%	0%	0%
St. Nicholas Cogeneration Project	0%	0%	0%	0%	0%	0%
John B. Rich Memorial Power Station	0%	0%	0%	0%	0%	0%
Ebensburg Power Company	0%	0%	0%	0%	0%	0%
Panther Creek Energy Facility	0%	0%	0%	0%	0%	0%
Kline Township Cogen Facility	0%	0%	0%	0%	0%	0%
Wheelabrator Frackville Energy Co Inc	0%	0%	0%	0%	0%	0%
Foster Wheeler Mt. Carmel Inc	0%	0%	0%	0%	0%	0%
Piney Creek Project	0%	0%	0%	0%	0%	0%

□	Large EGU units (>250 Mw) with no baseline control
░	Small EGU units (<250 Mw) with no baseline control
▓	Large EGU units (>250 Mw) with baseline control
□	Small EGU units (<250 Mw) with baseline control or de minimus emissions
▓	Announced to be closed

APPENDIX C
GRID-BY-GRID DIFFERENCES IN SCENARIO MODELING

As described in this report, the CMAQ modeling is conducted on a 36-km grid resolution. The average deposition of mercury for each grid cell is estimated for each scenario. This allows us to evaluate the changes on a grid cell basis in deposition for each scenario modeled. The grids for the state of Pennsylvania are shown in Figure C-1. Note that there are some grid cells that are only partially within the State.

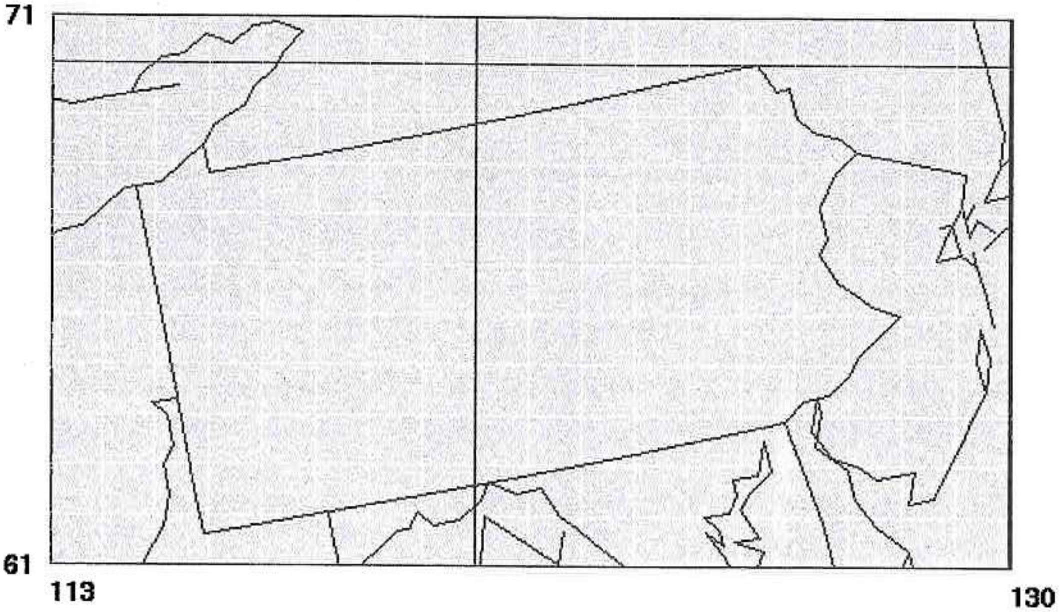

Figure C-1 – CMAQ Grids for Pennsylvania

The difference in deposition for each grid in Pennsylvania between Run 1 (the model for the Pennsylvania Mercury Rule) and Runs 2 and 3 are shown below in Tables C-1 and C-2.

Table C-1 – Grid by Grid Difference in Deposition between Run 1 and Run 2

	Column														
Row	114	115	116	117	118	119	120	121	122	123	124	125	126	127	128
70	0.78%	0.89%	0.75%	0.86%	0.92%	1.27%	1.13%	1.21%	1.15%	1.23%	1.18%	0.92%	0.75%	0.73%	0.54%
69	0.65%	0.78%	0.85%	1.30%	1.32%	1.88%	1.53%	1.58%	1.48%	1.70%	2.27%	1.19%	0.89%	0.98%	0.66%
68	0.36%	0.86%	1.11%	1.70%	1.90%	3.32%	2.30%	2.18%	1.97%	2.51%	9.65%	2.23%	1.25%	1.60%	0.76%
67	0.67%	1.39%	1.50%	2.62%	2.34%	7.39%	3.45%	2.49%	2.34%	3.18%	2.14%	1.86%	1.64%	4.36%	1.24%
66	0.70%	2.15%	1.98%	4.79%	4.66%	19.40%	8.36%	4.58%	3.78%	10.36%	4.11%	2.87%	1.48%	1.58%	0.72%
65	1.08%	2.14%	2.47%	8.94%	4.63%	5.04%	3.36%	2.67%	1.83%	2.88%	2.36%	4.84%	1.91%	1.20%	0.56%
64	0.66%	1.14%	0.63%	1.86%	2.07%	2.30%	2.11%	2.10%	1.71%	1.75%	1.38%	1.61%	1.19%	0.65%	0.48%
63	0.53%	0.72%	0.27%	0.94%	1.19%	1.43%	1.45%	1.48%	1.29%	1.43%	1.12%	1.22%	1.01%	0.69%	0.63%
62	0.39%	0.54%	0.53%	0.72%	0.77%	0.90%	1.05%	1.12%	1.04%	0.90%	0.72%	0.36%	0.65%	0.68%	0.82%
61	0.23%	0.39%	0.37%	0.43%	0.48%	0.59%	0.73%	0.84%	0.86%	0.77%	0.68%	0.45%	0.63%	0.63%	0.61%

Table C-2 – Grid by Grid Difference in Deposition between Run 1 and Run 3

	Column														
Row	114	115	116	117	118	119	120	121	122	123	124	125	126	127	128
70	0.05%	0.05%	0.04%	0.13%	0.14%	0.16%	0.16%	0.17%	0.17%	0.19%	0.18%	0.16%	0.13%	0.12%	0.11%
69	0.04%	0.03%	0.16%	0.16%	0.17%	0.19%	0.19%	0.20%	0.19%	0.24%	0.23%	0.18%	0.16%	0.14%	0.12%
68	0.09%	0.18%	0.20%	0.20%	0.23%	0.26%	0.24%	0.25%	0.24%	0.32%	0.44%	0.22%	0.18%	0.16%	0.13%
67	0.17%	0.25%	0.27%	0.31%	0.25%	0.34%	0.29%	0.28%	0.26%	0.38%	0.31%	0.24%	0.20%	0.18%	0.12%
66	0.19%	0.32%	0.35%	0.45%	0.45%	0.52%	0.41%	0.37%	0.30%	0.39%	0.31%	0.24%	0.19%	0.16%	0.10%
65	0.20%	0.20%	0.35%	0.61%	0.70%	0.54%	0.43%	0.37%	0.30%	0.30%	0.25%	0.24%	0.18%	0.09%	0.06%
64	0.28%	0.55%	0.23%	0.40%	1.12%	0.74%	0.57%	0.46%	0.34%	0.24%	0.24%	0.20%	0.17%	0.07%	0.07%
63	0.19%	0.24%	0.07%	0.24%	0.39%	0.40%	0.37%	0.33%	0.26%	0.22%	0.19%	0.15%	0.15%	0.09%	0.10%
62	0.18%	0.23%	0.21%	0.27%	0.32%	0.31%	0.33%	0.30%	0.24%	0.18%	0.14%	0.05%	0.12%	0.11%	0.03%
61	0.11%	0.16%	0.16%	0.16%	0.20%	0.21%	0.26%	0.25%	0.23%	0.18%	0.13%	0.08%	0.12%	0.11%	0.10%

APPENDIX D
ESTIMATION OF FRACTIONS OF EMITTED OXIDIZED AND ELEMENTAL MERCURY THAT DEPOSIT IN PENNSYLVANIA

As described in the text, ENVIRON conducted mercury modeling scenarios to evaluate the impact of alternative control scenarios for Pennsylvania. In addition to these scenarios, ENVIRON also evaluated the impact on deposition in Pennsylvania if there were no mercury emissions from EGUs in Pennsylvania (the Pennsylvania EGU "zero-out"). This zero-out run was conducted to allow the evaluation of the ratio of mercury deposition to the mercury emissions for each proposed control scenario. In other words, this scenario allows us to evaluate how much mercury of each different type that was released in Pennsylvania, deposits in Pennsylvania. Only elemental and oxidized mercury are contained in this evaluation, as there is little uncontrolled particulate bound mercury being emitted from Pennsylvania's EGUs at this time. The runs are shown in Table D-1.

Table D-1 – Scenarios Evaluated for Pennsylvania

	Oxidized Mercury		Elemental Mercury	
Run Number	>250 Mw	1-250 Mw	>250 Mw	1-250 Mw
1	90%	90%	90%	90%
2	90%	50%	---	---
3	90%	90%	---	---
Utility Zero Out				

As noted in the text, this study focused on elemental and reactive mercury species. Table D-2 shows the modeled deposition and anthropogenic emissions for each of the mercury species. Table D-3 shows the differences in both emissions and deposition for the two mercury species. By comparing the differences in deposition for each species, and the differences in emissions, the percent of the species that is predicted to deposit in the state can be calculated. This calculation is presented in Table D-3, and shows that less than 0.7% of the elemental mercury that is emitted from EGUs in Pennsylvania is deposited in Pennsylvania. On the contrary, approximately 25% of the oxidized mercury that is emitted form EGUs in Pennsylvania is deposited somewhere in Pennsylvania. This is consistent with our understanding of atmospheric chemistry of mercury compounds.

Table D-2 – Deposition and Anthropogenic Emissions of Elemental and Oxidized Mercury in Pennsylvania

		Anthropogenic PA Emissions [tons/yr]	Deposition [tons/yr]
zero out	Hg(0)	1.617	1.011
	Hg(2)	0.792	2.036
Run 1 (90/90/90)	Hg(0)	1.922	1.013
	Hg(2)	1.207	2.137
Run 2 (90/50/00)	Hg(0)	3.340	1.022
	Hg(2)	1.471	2.209
Run 3 (90/90/0)	Hg(0)	3.340	1.021
	Hg(2)	1.207	2.138

Table D-3 –Comparison of Emissions and Deposition in Pennsylvania between Potential Emissions Scenarios and Utility Zero-Out

		Anthropogenic Hg Emissions in PA [tons/yr]	Total Deposition [tons/yr]	Percent Emissions Remaining in PA
Run 1-zero out	Hg(0)	0.3050	0.002	0.73%
	Hg(2)	0.4150	0.1012	24.39%
Run 2-zero out	Hg(0)	1.723	0.0106	0.62%
	Hg(2)	0.679	0.1731	25.48%
Run 3-zero out	Hg(0)	1.723	0.0103	0.60%
	Hg(2)	0.4145	0.1024	24.69%

Comments of PPL Generation, LLC

in the matter of

Proposed Rulemaking Regulating
Mercury Emissions from Electric Generating Units
(Standards for Contaminants; Mercury)
36 Pa.B. 3185 (June 24, 2006)

Submitted to

The Pennsylvania Environmental Quality Board
Rachel Carson State Office Building
15th Floor, 400 Market Street
Harrisburg, Pennsylvania 17101-2301

August 25, 2006

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PPL Generation, LLC ("PPL"), an indirect owner of the Montour, Brunner Island and Martins Creek Steam Electric Stations, and a partial indirect owner of the Keystone and Conemaugh Steam Electric Stations, respectfully submits the following comments to the Pennsylvania Environmental Quality Board (the "Board"). These comments address the Board's proposed rule regarding the regulation of mercury emissions from coal-fired electric generating units ("EGUs") in Pennsylvania. The proposed rule and the preamble were published in the *Pennsylvania Bulletin* on June 24, 2006, at 36 Pa. Bulletin 3185 *et seq.* (hereinafter the "Proposed Rule" and the "Preamble," respectively). These comments are submitted pursuant to that notice.

EXECUTIVE SUMMARY

The Board has two legitimate objectives in proposing a rule, in accordance with Pennsylvania law: First, to the extent that the Board reasonably finds that mercury emissions from EGUs in Pennsylvania are contributing significantly to mercury deposition causing harm in Pennsylvania, then the Board may regulate those emissions of mercury as necessary to protect the public health, safety, and well-being of the citizens of this Commonwealth against the harm resulting from such contribution. Second, the Board is obligated to adopt rules to comply with the Clean Air Act and regulations promulgated thereunder, including the federal Clean Air Mercury Rule ("CAMR"). As explained below, the Board's Proposed Rule would greatly and unnecessarily burden EGUs in Pennsylvania, including PPL's units, without justification, and could also jeopardize Pennsylvania's compliance with CAMR. The Board must instead tailor the rules more specifically to these two objectives.

The Proposed Rule contains both (1) emissions standards and (2) annual caps on mercury emissions at each EGU that are based on CAMR allowance allocations. The Proposed Rule does not allow for emissions trading to comply with the emissions caps, even though CAMR established those caps with trading in mind. The emissions standards and annual caps are imposed in two phases, Phase 1 in 2010 and Phase 2 in 2015 (three years earlier than the 2018 date for Phase II under CAMR).

Although the emission standards might themselves be problematic for certain EGUs, far more problematic are the annual emissions caps that each EGU must meet without trading. Those caps for each EGU will be based on the state's mercury budget allocated by EPA under CAMR. EPA developed the state budgets with a national cap-and-trade program in mind an substantially under-allocated allowances to states that burn bituminous coal. As a result, in Phase 1 and Phase 2 respectively, EGU's in Pennsylvania would have to make in the range of 88% to 90% and 95% to 98% reductions in total mercury from the levels that exist in the bituminous coal supply. Meeting these draconian annual emissions caps renders superfluous the requirement in the Proposed Rule to meet a less stringent emissions standard of 80% (Phase 1) and 90% (Phase 2) reductions in total mercury for pulverized coal-fired EGUs, as well as provisions for presumptive technologies the Board would deem sufficient to meet these emissions reductions. In other words, installation of the identified presumptive technologies will not be sufficient for Pennsylvania's EGUs to achieve the CAMR budget allocation for the state. The result will be that the EGUs will have to go further to achieve an additional increment of reductions at great expense. Meeting the budget allocation through such reductions at each plant could well be infeasible. As there is no basis to believe surplus allowances will be available in the state to make up the shortfall, Pennsylvania may well end up unable to comply with CAMR and without recourse.

The Board's environmental rationale for its proposal, and for rejecting trading, is that mercury is a neurotoxin that deposits locally thereby causing "hot spots." However, the Board has offered no analysis in support of its contention that "hot spots" may exist or could create public health issues in Pennsylvania. Nowhere does the Board identify the methods used for calculating the risk to public health – rather than just baldly asserting that it exists. Nor does the Board offer any analysis of the methods to reduce such risks, the costs or the cost-effectiveness of such methods. The Board offers no evidence or analysis that "hot spots" even exist or present a public health threat.

Further, even if there is a legitimate concern about hot-spots, the Board has not explained why emissions reductions expected under CAMR and the Clean Air Interstate Rule will not be sufficient to address that concern such that a state-specific rule is needed. Finally, even if a state-specific rule is needed, the Board should not be requiring the proposed draconian reduction of *total* mercury emissions. The Board itself recognizes that it is *oxidized*[1] mercury that deposits in the Commonwealth. Emissions from Pennsylvania EGUs of *elemental* mercury do not deposit but instead travel in the atmosphere for up to a year as part of a larger global pool before oxidizing and depositing around the world. The attached report prepared by ENVIRON International Corporation (the "ENVIRON Report"), describes the deposition modeling it has conducted that demonstrates that elemental mercury emissions from Pennsylvania EGUs have no discernible impact on mercury deposition in the Commonwealth.

As it is oxidized mercury that has the potential to deposit locally, and as scrubbers are the most effective demonstrated technology to capture oxidized mercury, then adequate control of

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[1] Particle-bound mercury also deposits in Pennsylvania. However, those emissions are only 6% of the total mercury emissions from EGUs in Pennsylvania and particulate-bound mercury is already controlled to over 98% efficiency with the existing particulates controls installed at all EGUs in Pennsylvania pursuant to Pennsylvania's particulates requirements. URS Report at 3.

oxidized mercury should be all that the Board requires to address the deposition and "hot spot" issue. This technology would capture at least 90% of the oxidized mercury in the flue gas, and achieves the same reduction in mercury deposition as a 90% reduction in both oxidized and elemental mercury from such units. In fact, requiring Pennsylvania's EGUs to go further to capture the elemental mercury could well prove slightly counterproductive. This is because certain technologies that enhance capture of elemental mercury, such as Selective Catalytic Reduction ("SCR"), function by first oxidizing the mercury so that the scrubbers and ESPs will capture it. Although this may reduce the *total* mercury emissions, the *oxidized* component that deposits locally may actually be slightly higher, because a small amount of the additional newly oxidized mercury will be released and possibly deposited rather than captured.

The Board has also grossly underestimated the cost of implementing the Proposed Rule. The Board erroneously based its cost estimates on the cost of simply meeting the 90% reduction emissions standard. The cost estimate overlooks the cost necessary to obtain the 95% or greater reductions necessary to meet the CAMR-based annual emissions cap without trading. In Phase 2, to meet the annual cap without trading will require extraordinary capital investments and operating costs. In fact, as explained in the attached analysis of control technologies and costs prepared by URS Corporation (the "URS Report"), the costs *per unit* to comply with Phase 2 of the Proposed Rule will exceed the cost the Board projected for *all* EGUs combined. This extreme cost will not provide any environmental benefit to Pennsylvania beyond what could be achieved by requiring 90% control of *oxidized* mercury only.

Moreover, the Department incorrectly claims that the Proposed Rule is necessary to offset the inequity in CAMR with regard to bituminous coal. To be sure, as explained in the report prepared by NERA (the "NERA Report"), CAMR under-allocated allowances to EGUs burning bituminous coal, with the result that achieving the annual emissions caps based on those allowances requires 95% or greater reductions in total mercury from bituminous coal. Rather than assisting bituminous coal and the EGUs that burn that coal, the Proposed Rule will increase the burden drastically compared to their burden under CAMR by prohibiting trading to meet the annual caps. The presumptive technologies designed to benefit bituminous coal in fact do not provide any help, because they are not sufficient to achieve compliance with the CAMR-based annual emissions cap. Without trading, EGUs burning bituminous coal will still need to install additional controls to reduce elemental mercury emissions with no discernible benefit on deposition in Pennsylvania even *after* they have controlled the oxidized mercury that could potentially deposit in the Commonwealth. Thus, for no benefit in Pennsylvania they are saddled with this additional burden that CAMR does not impose to control the elemental mercury at their units regardless of costs and even if the cost is drastically higher than the cost of reducing such elemental mercury at other units and corresponding price of allowances.

For these reasons, the Board should properly analyze whether hot spots are a legitimate public health concern for Pennsylvania. If so, then the Board should determine whether mercury reductions expected to be made in Pennsylvania under CAMR and CAIR would be sufficient to address the concern. If the Board concludes that state-specific regulation is required, then the Board should structure the rule as follows. First, the Board should implement CAMR, with unrestricted trading of allowances, to comply with the federal budget allocation for *total* mercury. This will ensure that Pennsylvania fulfills its federal obligation in a cost-effective manner that is suitable for controlling elemental mercury as a global pollutant. Second, the Board should adopt an overlay on CAMR to address state-specific environmental concerns.

Specifically, the Board should adopt requirements that EGUs achieve a specified level of control of *oxidized* mercury at each EGU.

BACKGROUND

A. BACKGROUND REGARDING MERCURY EMISSIONS

1. TYPES OF MERCURY AND THEIR BEHAVIOR IN THE ENVIRONMENT

Mercury is present in the atmosphere primarily as a gas in three distinct forms that behave very differently: elemental mercury (also known as Hg^0); oxidized mercury (also known as Hg^2, or reactive gaseous mercury); and particle-bound mercury (a form of oxidized mercury, also known as Hg^P). *See* ENVIRON Report at 3-1 to 3-2. The Preamble also discusses in some detail the distinctions between oxidized and elemental mercury and the behavior of each. *See* Preamble at 3185 – 86, 3192.

Elemental mercury is very volatile and does not dissolve readily in water. It deposits very slowly from the atmosphere to the earth's surface as part of a "global pool" until it oxidizes in the atmosphere to reactive oxidized mercury over great distances and a long period of time. Elemental mercury emissions remain in the atmosphere for about a year as it is transported from its source around the earth. *See* ENVIRON Report at 3-1; Preamble at 3185 ("The lifetime of elemental mercury (Hg^0) is estimated to be up to 1 year. . . .").

Oxidized mercury is water soluble and chemically reactive. It deposits more readily to the earth's surface, dissolving in rain and in plant leaf tissues or surface water. Oxidized mercury emissions likely remain in the atmosphere for no more than a few days and generally are transported no more than a few hundred miles before depositing. *See* ENVIRON Report at 3-2; Preamble at 3185 ("oxidized forms [of mercury] have a lifetime of only a few days because of particulate settling and solubility."). Oxidized mercury, once deposited, may also be re-emitted to the atmosphere as elemental mercury.

Particle-bound mercury includes mercury compounds attached to a host aerosol or particle and also deposits relatively efficiently, depending on the size of the host particle and weather conditions. The mercury that attaches to a host particle is generally oxidized, so that particle-bound mercury can also be viewed as a subset of oxidized mercury. *See* ENVIRON Report at 3-2.

The mercury compound found in animal tissues and that accumulates in fish is virtually all methyl mercury, an organic mercury compound that forms through the activity of microorganisms after atmospheric mercury deposits on the surface of the earth. *See* ENVIRON Report at 3-3; Preamble at 3185 ("Methylmercury is formed by biological processes after Hg precipitates from air to water.").

2. FORMATION OF TYPES OF MERCURY IN EGUs

During combustion in a coal-fired EGU, mercury in the coal is released into the exhaust gas as elemental mercury. The elemental mercury may then be oxidized in the exhaust gas stream and a portion of that oxidized mercury may also then form particle-bound mercury in the exhaust gas. *See* URS Report at 3; Preamble at 3185. Oxidation of elemental mercury in the flue gas is largely through reaction with chlorine found in the coal or through reactions on the surface of particles. Bituminous coals that are generally used in Pennsylvania tend to have higher chlorine content than sub-bituminous coals from the West, for example, and the bituminous coals therefore tend to generate higher levels of oxidized mercury emissions, in the range generally of *50 to 90%. See* URS Report at 9.

3. EMISSIONS CONTROLS FOR DIFFERENT TYPES OF MERCURY

The effectiveness of mercury emission control technologies for coal-fired EGUs depend substantially on the type of mercury in the flue gas. *See* URS Report at 9; Preamble at 3185 ("The ability of an air pollution control system to capture the mercury is dependent, in part, on the species of the mercury in the flue gas."). Technologies used to remove particulate matter such as electrostatic precipitators ("ESPs"), and fabric filters (also known as "bag houses"), are highly efficient in removing particle-bound mercury together with other particulates, achieving in the range of 98% or greater removal efficiency. URS Report at 3. Technologies used to remove sulfur dioxide (SO_2), such as wet scrubbers can remove 90% or more of oxidized mercury, as well, taking advantage of the solubility of oxidized mercury in water. There are no more effective technologies demonstrated to remove oxidized mercury. URS Report at 6, 14.

Wet scrubbers do not, however, themselves remove elemental mercury that will pass straight through these control devices. The most tested option to remove the elemental mercury is to rely on technologies to oxidize a greater fraction of the elemental mercury to the oxidized form before it reaches the scrubber. Selective Catalytic Reduction ("SCR"), which is generally installed to control nitrogen oxide ("NO_x") emissions, and injection of halogenated chemicals, also have been observed to increase the oxidation of elemental mercury, which can then be captured in the scrubbers. Other technologies, such as activated carbon injection ("ACI"), operate by adsorbing elemental mercury onto particles, which can then be captured in a fabric filter. But in comparison to scrubbers with respect to oxidized mercury, testing of ACI has shown greater variability and appears to depend to a greater extent on the design of the particular unit. URS Report at 19-20.

4. MERCURY EMISSIONS FROM COAL-FIRED EGUS IN PENNSYLVANIA

As described in the Preamble, Pennsylvania has 36 coal-fired power plants with 78 EGUs, representing 20,000 MWG of generating capacity. *See* Preamble at 3185. These plants account for approximately 77% of total annual mercury emissions in the state.

Because EGUs in Pennsylvania burn predominantly bituminous coal high in chlorine content (which tends to oxidize elemental mercury in the flue gas), they tend to emit more oxidized mercury and less elemental mercury as compared to EGUs in the West that burn predominantly sub-bituminous coal with lower chlorine content. The portion of mercury emitted from Pennsylvania EGUs is approximately 64% oxidized, 36% elemental, and 0.1% particle-bound, based on the corrected 2001 baseline. ENVIRON Report at B-1 to B-2.

5. PPL'S COAL-FIRED EGUS IN PENNSYLVANIA

PPL owns and operates three coal-fired power plants in Pennsylvania (Montour, Brunner Island and Martins Creek), and partially owns two more operated by Reliant Energy (Keystone and Conemaugh). Note that the two small coal-fired units at the Martins Creek Station are planned to be retired in 2007, and so are not further discussed in this document. As a supplier of steady, reliable power and employer in Pennsylvania, PPL contributes significantly to the economy of the area and to the well-being of the residents.

The coal fired in the PPL Pennsylvania units is primarily Eastern bituminous coal mined in Pennsylvania. The coal has a medium to high sulfur content, and relatively high mercury content compared to other Eastern bituminous coals. The coals fired in the PPL Pennsylvania units are expected to contain more than 100 ppm of chlorine, and thus should produce mostly oxidized mercury in the flue gas. The mercury content of coal can be quite variable. Based on sampling conducted by PPL, the mean concentration is 21.8 lb/ T Btu.

ESPs are used for particulate control in Brunner Island Units 2 and 3, and Montour Units 1 and 2. Brunner Island Unit 1 uses an alternate particulate control technology, a fabric filter. None of the PPL Pennsylvania units currently are equipped with wet scrubbers for sulfur dioxide control. However, scrubber retrofits are underway, and by 2010. all three units at Brunner Island and both units at Montour will be scrubbed. Additional detail regarding the PPL units is presented in the URS Report at 9 to 13.

B. RULEMAKING BACKGROUND

1. THE FEDERAL CLEAN AIR MERCURY RULE ("CAMR")

a. REDUCTION REQUIREMENTS AND IMPLEMENTATION DATES

On March 15, 2005, EPA promulgated CAMR, a comprehensive regulatory scheme that established "new standards of performance for mercury (Hg) for new and existing coal-fired electric utility steam generating units (Utility Units), as defined in Clean Air Act (CAA) section 111." 70 Fed. Reg. 28,606. Under CAMR, EPA capped total mercury emissions (without regard to the different types of mercury, discussed above),[2] at nation-wide levels in two phases: (1) a Phase I cap of 38 tons per year (tpy), which becomes effective in 2010; and (2) a Phase II cap of 15 tpy which becomes effective in 2018. In setting these reduction requirements, EPA allocated each state an annual EGU mercury budget for the appropriate compliance periods. *See* 40 C.F.R. § 60.24. Pennsylvania's annual EGU total mercury budget is 1.78 tpy for the period of 2010 to 2017, and 0.702 tpy from 2018 and thereafter.

The sum of all of the state annual EGU mercury budgets equals the levels set by the two-phase cap-and-trade program (38 and 15 tpy, respectively). EPA set these cap levels by examining the emission reduction technology currently available to reduce mercury emissions and those in development, again focusing on reductions in total mercury emissions without regard to the type of mercury controlled. In setting the standards of performance, EPA noted that currently developed mercury-specific technologies have not "demonstrated an ability to consistently reduce Hg emissions by 90 percent (or any other level) at the present time" and that new control technologies cannot be developed and widely implemented within the next five

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[2] EPA's focus on total mercury emissions rather than only oxidized mercury derives from EPA's interest in long-range and even global deposition in addition to local deposition, and its allowance trading program matches the broad geographic dimensions associated with such mercury emissions.

years (*i.e.*, by 2010). 70 Fed. Reg. 28,615; 28,618 - 28, 619. EPA found, however, that "Hg-specific air pollution control technologies such as ACI are adequately demonstrated for use sufficiently before 2018 to allow for their deployment across the field of units to comply with the Phase II cap in 2018." 70 Fed. Reg. 28,619. Therefore, while full scale technologies cannot "be developed and widely implemented within the next 5 years . . . it is reasonable to assume that this can be accomplished over the next 13 years" (*i.e.*, by 2018). 70 Fed. Reg. 28,619. In short, technologies specifically focused on reducing total mercury are not available in the near-term but are anticipated to become available in the longer term.

Recognizing that emissions control technologies to reduce SO_2 and NO_x emissions in the eastern states under the Clean Air Interstate Rule ("CAIR") would also reduce emissions there EPA concluded that it was rational to design CAMR's reduction levels and implementation schedule to work together with CAIR as part of a "carefully designed 'multi-pollutant' approach, a program designed to control NO_x, SO_2, and Hg at the same time . . . ." 70 Fed. Reg. 28,617. EPA based its Phase I mercury cap of 38 tpy on the Agency's prediction of the number of wet scrubbers that will be installed by 2010 under CAIR, and an assumption that those scrubbers would produce reductions in total mercury nationwide of approximately 50% from 2000 levels. 70 Fed. Reg. 28,617. EPA anticipated that this co-benefit would provide time for the development of additional control technologies and allow sources to meet CAMR's Phase II cap.[3] EPA projects that sources can meet the second phase of the cap by the combined use of the co-benefit and mercury controls it expects to be "installed and operational on a nationwide basis." 70 Fed. Reg. 28,621.

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[3] CAMR's Phase II cap of 15 tons per year was also set by EPA considering a level that "does not have significant impacts on energy supply and the cost of energy to the consumer." 70 Fed. Reg. 28,621.

CAMR is to be implemented by the states and each state is to submit its own implementation rules to EPA by November 17, 2006 for review and approval as part of the state's State Implementation Plan ("SIP"). 40 C.F.R. § 60.24(h). If the states do not adopt and submit such rules to EPA, EPA will implement the federal rules in that state instead. Accordingly, Pennsylvania is required to adopt and submit rules satisfying the minimum elements of CAMR to EPA in November.

b. CAMR'S CAP-AND-TRADE PROGRAM

Integral to CAMR is the cap-and-trade program that requires that each facility hold one "allowance" for each ounce of mercury emitted in any given year. Those allowances can then be traded with other regulated EGUs. As the CAMR state budget allocations must also encompass emissions from new development, EPA recommends that states reserve five percent of the allowances under their caps in 2010 through 2014 for new development and three percent in subsequent years. *See* 70 Fed. Reg. 28,666.

As explained in the CAMR Final Rule, "a 'cap-and-trade' approach to limiting total Hg emissions is the most cost-effective way to achieve reductions in Hg emissions from the power sector." 70 Fed. Reg. 28,606. The cap-and-trade approach ensures that reductions are achieved cost-effectively by providing an incentive to EGUs to reduce their emissions below the number of allowances they receive, and to get the most out of installed technology if the EGUs can cost-effectively go beyond the emissions limit for the unit in question. That way, EGUs may then sell their allowances on the open market. Moreover, EPA's cap-and-trade program also encourages the development of mercury emissions reduction technology. 70 Fed. Reg. 28,615. This is because those EGUs that are successful in reducing emissions will avoid the need to buy allowances at their market price, or again, will free up allowances to sell or bank[4] for future use. The cap-and-trade system is particularly important where the costs of meeting allowance allocations vary among sources, and is particularly relevant to Pennsylvania. This is because the EPA budget allocations impose greater emissions reduction obligations on EGUs like those in Pennsylvania that burn bituminous coal than on EGUs that burn other coal types. EPA based its mercury allowance allocations on heat input, and established state budget allocations based on each state's fraction of total EGU heat input. However, EPA made an adjustment to increase the allocation percentage for states based EGUs in the state that burn sub-bituminous coal or lignite, because EPA believed mercury reductions would be more difficult to achieve for such fuels. Because the overall national mercury inventory is a fixed amount, the additional allowances allocated for bituminous coal and lignite had to be offset by reducing the allocation for bituminous coal, in "zero sum" fashion.

In the end, EPA's budget allocation for bituminous coal is very stringent and compliance will be costly. Specifically, the Pennsylvania budget, assuming the recommended 5% hold-back for new sources, effectively results in a requirement to capture 95-98% of total mercury in the coal for large EGUs, a level of stringency that would strain the limits of feasibility were the EGUs to make those reductions themselves without any opportunity to purchase allowances to achieve the last increment of reductions that might be infeasible or overwhelmingly expensive. URS Report at 26-31. DEP has repeatedly criticized CAMR for imposing an unfair burden on

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[4] CAMR's cap-and-trade program also allows "banking," or holding, of allowances which may use be used without restriction. *See* 70 Fed. Reg. 28,630. The NERA Report describes the advantages of banking. Banking allows early reductions in mercury emissions at the outset beyond CAMR's Phase I limits, which then can be used later to provide cushion and flexibility in achieving the more stringent Phase II limits. This cushion, in turn, will encourage EGUs to make early reductions wherever possible, and has the added benefit of achieving environmental benefits sooner. NERA Report at 15.

EGUs burning bituminous coal. See, Letter dated June 29, 2004 from Nicholas A. DiPasquale, Deputy Secretary for Air, Recycling and Radiation Protection to U.S. EPA Docket ID No. OAR-2002-0056 ("... the proposed rules establish control requirements that improperly sub-categorize by coal type and establish a bias against bituminous coal."); Letter dated January 3, 2005 from Secretary McGinty to U.S. EPA Docket ID OAR-2002-0056 ("One of the most troublesome aspects of EPA's proposed mercury control options is the unfairly disproportionate burden on eastern coal."). DEP has noted that CAMR will require reductions of total mercury emission of 76% from the 1999 baseline emissions for Pennsylvania EGUs, while requiring no reductions for EGUs in western states. *See* "Comments Submitted By: The States of New Jersey, . . . Pennsylvania . . . and Wisconsin In Re Reconsideration of [CAMR]", December 19, 2005, p. 29.

EPA's allowance analysis suggest that states such as Pennsylvania (with EGUs burning mostly sub-bituminous coal), would be net buyers of allowances, unable cost-effectively to achieve the budget allocation with in-state controls. NERA Report at 27. Instead, the EPA analysis implies that it will be less costly to purchase the last incremental emissions reductions that might be made elsewhere less expensively than making that last increment of reductions at the Pennsylvania EGUs. In effect, EPA's analysis suggests that CAMR imposes obligations on Pennsylvania EGUs that are more stringent and costly than on EGUs located elsewhere and thus effectively will require Pennsylvania sources to pay for reductions made in other states.

The trading system ameliorates the impact of this misallocation of allowances and under-allocation to bituminous coal burners in Pennsylvania, where it would be very costly or infeasible for sources to comply with their allowance allocations. With allowances available for purchase, the regulators do not have to provide exceptions or lower the emissions standards to a "lowest common denominator." Specifically for Pennsylvania, although EPA's budget allocation is overly stringent in requiring capture of 95-98% of total mercury in the coal, the allowance system provides a cushion so that the upper bound on control costs is the price of allowances that Pennsylvania EGUs would be required to purchase from sources in other states to meet that budget.

2. THE BOARD'S PROPOSED PENNSYLVANIA RULE

States have the option to adopt CAMR by reference and to participate in the EPA cap-and-trade program. Pennsylvania has rejected the option of adopting CAMR and has rejected participation in the cap-and-trade program. Pennsylvania has opted instead to develop its own state-specific rule. If a state does not participate in the EPA cap-and-trade program the mercury emission budget becomes a "firm cap" on the total mercury emission in the state. 70 Fed. Reg. 28,624 (May 18, 2005). Thus, the Pennsylvania program will need to demonstrate to EPA the mercury emissions in the Commonwealth will not exceed the CAMR budget.

The Proposed Rule imposes two types of control on mercury emissions from EGUs: (1) Emissions Standards and (2) an Annual Emissions Limit. Both types of controls apply with Phase 1 beginning in 2010 and Phase 2 beginning in 2015 (three years earlier than Phase II under CAMR). The Annual Emissions Limit is more stringent and renders the Emissions Standards essentially superfluous in both Phase 1 and Phase 2. Also, although the Preamble discusses at length the different species of mercury emissions and the species of expected emissions from Pennsylvania EGUs (Preamble at 3185 - 86, 3192), the Proposed Rule does not address specific species of mercury emissions. Rather the Emissions Standards and Annual Emissions Limits apply to total mercury.[5]

a. EMISSIONS STANDARDS

Each unit (or facility) must achieve certain reductions in total mercury emissions. In Phase I (by 2010), existing pulverized coal-fired EGUs must control total mercury emissions by 80% as measured from mercury content of the coal, or achieve an emission rate of 0.024 lbs per GWh. In Phase II (by 2015), these units must meet 90% control efficiency or 0.012 lbs per GWh.[6] *See* section 123.205(c). The Preamble explains that these reductions will likely be obtained through the use of certain presumptive technologies that may already be installed or are anticipated to be installed to comply with CAIR. Specifically, the Board asserts that units burning 100% bituminous coal and controlling emissions through an ESP and wet scrubber will be able to meet the Phase I requirement for 80% control of emissions. The Board asserts that units using those technologies plus SCR will be able to meet the 90% reduction requirements for Phase II. Preamble at 3186. The Proposed Rule provides that units burning 100% bituminous coal and employing the aforementioned control technologies will not need to make any further compliance demonstration with regard to the Emission Standard. *See* Section 123.206(b).

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[5] The Proposed Rule imposes monitoring, testing and record keeping requirements that are essentially the same as required by CAMR.

[6] For circulating fluidized bed EGUs, the corresponding requirements are 95% control and 0.0058 lb. in both phases.

b. ANNUAL EMISSIONS LIMITS

Each EGU must also comply with an Annual Emission Limit by holding non-tradable allowances. *See* Section 123.207(a). DEP proposes to allocate these allowances based on the EPA budget of mercury emission allowances granted under CAMR. CAMR grants Pennsylvania 1.78 tpy under Phase 1 and 0.702 tpy under Phase 2. The Proposed Rule would reduce these amounts by set asides for potential new units, setting aside 5% during Phase 1 and 3% during Phase 2. Accordingly, DEP would allocate slightly less than the full EPA CAMR budget. In addition, the reduced Phase 2 budget would be effective in 2015 under the proposal rather than in 2018 under CAMR.

DEP has indicated that the purpose of the Annual Emission Limit or allowance system is to provide "regulatory assurance that the Commonwealth meets the EPA CAMR mercury state budget." Preamble at 3190. EGUs that meet the Emissions Standard will not necessarily also meet the Annual Emissions Limit and may need to implement further reductions beyond the presumed technologies. In fact, the allowances allocated to EGUs to establish their Annual Emissions Limits are so restricted that achieving the mandated 90% emission reduction will not be sufficient to comply with the Annual Emission Limit.

EGUs will be required to report their actual emissions annually.[7] Each year, beginning in 2010, EGUs may petition for additional emission allowances from the supplemental pool and DEP will decide if and how to allocate any extra allowances. Apparently recognizing that the mandated emission reductions will not necessarily meet the EPA imposed budget, DEP has indicated that the petition process is designed for those units who have installed "optimum

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[7] If actual emissions in any year are less than the amount set aside for that unit under the Department's allocation program, those allowances will be placed in the annual emission limit supplement pool for reallocation by DEP.

control technology" but are still unable to meet the annual emission limit. Preamble at 3190. The proposal does not define "optimum control technology." Allowances, however, will be allocated by DEP on a strict priority basis set out in the proposal. *See* 127.209(g). Allowances will be available for allocation only to the extent that they are present in the pool. Allocations in the pool must come from either the set-aside for new EGUs or from other units that use less than their annual allocation. There is no provision for obtaining allowances from sources outside of the Commonwealth or for trading allowances generated in Pennsylvania to out-of-state facilities. If an EGU installs "optimum control technology" but still has insufficient allowances and if there are insufficient allowances in the state pool, then the EGU will need to curtail operation, shut down, or obtain an alternative limit that will jeopardize the state's compliance with its CAMR budget.

PPL POSITION ON PENNSYLVANIA PROPOSED RULE

The Board's proposed rule would not comply with the Pennsylvania Air Pollution Control Act ("APCA") or Executive Order 1996-1, and would be arbitrary and capricious. The Board should revise the proposed rule to: (1) implement CAMR with unrestricted trading of allowances for *total* mercury in order to comply cost-effectively with federal requirements; and (2) specifically limit emissions of *oxidized* mercury from Pennsylvania's EGUs as appropriate to resolve concerns about mercury deposition in Pennsylvania

I. THE PROPOSED RULE'S REQUIREMENTS FOR TOTAL MERCURY ARE NOT JUSTIFIED TO ADDRESS MERCURY DEPOSITION IN PENNSYLVANIA

A. PENNSYLVANIA LAW REQUIRES THAT THE MERCURY RULE BE REASONABLY NECESSARY AND NO MORE STRINGENT THAN CAMR UNLESS THERE IS A COMPELLING STATE INTEREST

The first objective of the Commonwealth of Pennsylvania as stated in the APCA is to "protect the air resources of the Commonwealth *to the degree necessary*" for protection of public health, safety and well-being, *and* for development, attraction and expansion of industry, commerce and agriculture. 35 P.S. § 4002(a) (emphasis added). Thus, the Legislature has made the basic policy choice that air quality regulations must contain a balance. Such basic policy choices are to be made by the Legislature, not administrative agencies. *See* William *Penn Parking Garage, Inc. v. City of Pittsburgh*, 464 Pa. 168, 212, 346 A.2d 269 (1975). Where regulations are not rationally related to state objectives as declared by the Legislature or are unnecessarily stringent and unnecessary for the protection of the public health, the regulations may be challenged as unreasonable. *See Commonwealth of Pennsylvania v. Locust Point Quarries, 396 A.2d 1205, 483 Pa. 350 (1979)* and *Rochez Bros., Inc. v. Commonwealth of Pennsylvania*, 334 A.2d 790, 795, 18 Pa. Cmwlth. 137, 146 (1975). Regulations that impose significant burdens on Pennsylvania industry without corresponding benefit to the environment surely fail to adhere to the Legislature's intended purpose.

A second objective of the APCA is "implementation of the [federal] Clean Air Act in the Commonwealth." 35 P.S. § 4002(a)(v). The APCA obligates the Board to adopt regulations to implement provisions of the federal CAA and EPA rules and regulations promulgated under the CAA. 35 P.S. § 4005(a)(8). That provision further specifies that the Board's regulations "shall be consistent with the requirements of the Clean Air Act and the regulations adopted thereunder." 35 P.S. § 4005(a)(8).

Moreover, the Board must be mindful that Executive Order 1996-1 prohibits the Board from adopting mercury rules that are more stringent than CAMR (as the corresponding federal mercury rules), unless the Board determines that the proposed rule is necessary to meet a compelling and articulated Pennsylvania interest. Specifically, the Executive Order provides that, "[w]here federal regulations exist, Pennsylvania's regulations shall not exceed federal standards unless justified by a compelling and articulable Pennsylvania interest or required by state law."[8]

In short, the Board's regulations under the APCA must be rationally related to the APCA's objectives of (1) protecting public health, safety and well-being to the degree necessary; (2) development, attraction and expansion of industry and (3) implementing the federal CAA, and may not be either unnecessarily stringent or inadequate to achieve such purposes.

B. THE PROPOSAL'S REQUIREMENTS TO CAP TOTAL MERCURY EMISSIONS WITHOUT TRADING ARE UNNECESSARY TO PROTECT THE PUBLIC AND COULD JEOPARDIZE COMPLIANCE WITH CAMR

1. REQUIREMENTS FOR OXIDIZED MERCURY ARE ALL THAT IS NECESSARY TO PROTECT THE PUBLIC

The Board has sought to justify its proposed rule on the grounds that the cap-and-trade approach under CAMR "will significantly delay the control of mercury emissions from the utility sector and will create 'hot spots' of mercury exposure that could be very detrimental to humans and wildlife." Preamble at 3189.[9] Even assuming there is credible scientific evidence to support a concern about hot-spots in Pennsylvania under CAMR, the Board's analysis that the Proposed Rule will benefit the Commonwealth is fundamentally flawed. The Proposed Rule

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[8] As a general matter, Executive Order 1996-1 directs that "[r]egulations shall address a compelling public interest"; that the "[c]osts of regulations shall not outweigh their benefits"; that the "[r]egulations shall address definable public health, safety or environmental risks." Moreover, the Executive Order requires that the preamble to each regulation describe in nontechnical terms the compelling public need the regulation is designed to address.

[9] The preamble also states two other grounds for opposing EPA's cap-and-trade program. First, the preamble explains that DEP believes EPA did not have legal authority to regulate mercury through a cap-and-trade program under section 111 rather than under Section 112 of the CAA. Preamble at 3189. As challenges to EPA's legal authority under the CAA have been filed and will be resolved in due course, that is not a matter that warrants scrutiny here. *See State of New Jersey et al v. United States Environmental Protection Agency, Docket No. 05-1162, D.C. Cir.*. For now, the EPA regulations are valid at least until the D.C. Circuit decides otherwise. Second, the preamble explains that DEP believes that CAMR requires "greater reductions from coal-fired units that burn bituminous coal from states like this Commonwealth" presumably as compared to units burning other coal types, and that a fuel-neutral approach is more appropriate. The burden CAMR places on bituminous coal is discussed further in Section III (below).

does not specifically address oxidized mercury as the alleged cause of hot spots. Rather, the Board's requirement of compliance with Annual Emissions Limits of 95%-98% capture of mercury in the coal without any allowance trading, applies to *total mercury* rather than *oxidized mercury*. It is *oxidized mercury* emissions from EGUs in Pennsylvania that could be said to present a "definable environmental risk" for the citizens of the Commonwealth due to its greater propensity to deposit locally.[10] Elemental mercury, in contrast, will not contribute to "hot spots" or any other harm in Pennsylvania. In fact, the proposed rule could directionally *increase* deposition of mercury in the Commonwealth. This is because the Annual Emission Limit on total mercury emissions imposed on each EGU cannot be met without making reduction in elemental mercury as well and without trading those reductions will have to be extremely high. The elemental mercury may have to be oxidized in order to capture it, which could actually *increase* oxidized mercury emissions.

a. OXIDIZED AND NOT ELEMENTAL MERCURY IS THE ENVIRONMENTAL CONCERN IN PENNSYLVANIA

The Preamble to the Proposed Rule itself emphasizes that the severe requirements (including adding SCR as presumptive technology, the 2015 date and the restrictions on trading), are justified to reduce deposition of *oxidized* mercury:

> The Commonwealth is concerned that the CAMR's cap and trade approach will result in hot spots to which this Commonwealth is particularly susceptible given that all 36 coal-fired utilities in this Commonwealth burn bituminous coal as their primary fuel source. Bituminous coals generally have high mercury, chlorine and sulfur contents and low calcium content, resulting in a high percentage of organic mercury. This type of mercury has a residence time of a few days and is deposited near the source of the release.

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[10] See footnote 1 regarding particle-bound mercury, which is adequately controlled and thus not currently a significant concern in Pennsylvania.

> Therefore, it is not a suitable candidate for emission trading against emission reductions in other regions because it results in hot spots.

Preamble at 3192. Plainly, the Board identifies as its environmental concern the oxidized mercury that might deposit close to the sources and lead to so-called "hot spots."

To be sure, a substantial fraction of mercury emissions from coal-fired EGUs in Pennsylvania is oxidized, and reductions in oxidized mercury at coal-fired EGUs would reduce the amount of mercury that is deposited in Pennsylvania. Indeed, the scrubbers and ESPs that the Preamble identifies as presumptive technology for Phase 1 in 2010 should remove at least 90% of the oxidized mercury that the Board professes is the source of the "hot spot" problem. URS Report at 6, 14.[11] Those technologies and the mercury reductions they achieve, however, will "protect the air resources of the Commonwealth to the *degree necessary*" to protect human health and the environment in Pennsylvania, and it will already be accomplished in the Phase 1 timeframe.

These technologies would not, of course, control the fraction of mercury that is emitted in its elemental form, on the order of 30-36% for the vast majority of units in Pennsylvania that burn bituminous coal. But that elemental mercury is of little consequence to Pennsylvania. It does not deposit here but instead constitutes a very small fraction of a global pool that will circulate for approximately one year before depositing almost all outside of Pennsylvania. (As described in the Preamble, coal-fired power generation in the Untied States contributes only about 1.2 percent of approximately 4,000 tons of annual global anthropogenic mercury emissions, and of Pennsylvania EGUs' total of about 3.85 tons of annual mercury emissions units the elemental fraction accounts for approximately 1.25 tons, or 0.03 percent of the global

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[11] Existing particulate controls already remove on the order of 98% of the particle-bound mercury, which also tends to deposit relatively near the source. URS Report at 3.

pool of mercury emissions.) Of course, elemental mercury must be controlled as part of the total mercury requirements under EPA's CAMR, which takes into account the federal interest in weighing and addressing the overall U.S. contribution to the international issue of global elemental mercury emissions. However, that is no reason for Pennsylvania to impose a hard cap on total mercury emissions that in effect requires substantial reductions in elemental mercury emissions that do not deposit in Pennsylvania.

b. MERCURY DEPOSITION MODELING CONFIRMS THIS CONCLUSION

ENVIRON mercury deposition modeling for Pennsylvania confirms the conclusions that: (1) controls on elemental mercury emissions at coal-fired EGUs in Pennsylvania barely affect deposition of mercury in Pennsylvania; and (2) use of wet scrubbers that are anticipated to be in place by 2010 eliminate any discernible contribution from coal-fired EGUs to mercury deposition in the Commonwealth. *See* ENVIRON Report at 4-6. ENVIRON modeled mercury deposition in Pennsylvania on the assumption that all EGU achieved a 90% reduction in both oxidized and elemental mercury emissions in the Commonwealth (comparable to the 90% reduction in total mercury specified to meet the Emissions Standards in Phase 2 of the Proposed Rule). ENVIRON then modeled two scenarios in which only oxidized mercury emissions from large EGUs, (over 250 MWG), are controlled at 90%, corresponding to the control anticipated from wet scrubbers.[12] The two scenarios differ only with respect to oxidized mercury emissions from smaller EGUs, which were modeled at the same control as for large EGUs (90%), and at 50% control (to represent a potential minimum control for smaller units). In both of these scenarios, elemental mercury emissions were uncontrolled.

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[12] In both scenarios, ENVIRON assumed particle-bound mercury is controlled at 98%, based on the control efficiencies achieved by current technologies that are currently in place. *See* ENVIRON Report at 1-1, 4-5; URS Report at 3.

Two important conclusions can be drawn from the modeling results. First, controlling oxidized mercury *only* with scrubbers (which achieve at least 90% capture of the oxidized mercury emissions), resolves the contribution of Pennsylvania's EGUs to mercury deposition in Pennsylvania. Adding reductions in elemental mercury to the reductions in oxidized mercury make no discernible difference for deposition in Pennsylvania. Comparing the scenario in which oxidized mercury is controlled at 90% to a scenario where both oxidized and elemental mercury are controlled at 90% shows only a 0.3 % difference in mercury deposition. *See* ENVIRON Report at 4-5 to 4-6. Hence, there is no added benefit in Pennsylvania from adding control of the elemental mercury.

Second, controlling oxidized mercury from smaller units (less than 250 MWG), has only a modest impact on mercury deposition in Pennsylvania. ENVIRON's modeling evaluated the impact of such controls at 50% and 90% capture. The results show limiting controls for such units to 50% capture increase mercury deposition by approximately 2.4 %.

In short, to achieve the Board's first objective of addressing mercury deposition in the Commonwealth, the Board need only require control for oxidized mercury. Both the atmospheric chemistry and ENVIRON modeling establish that requiring control of oxidized mercury emissions from specified EGUs in Pennsylvania is equally effective in eliminating any potential contribution to "hot spots" or other harm to humans and the environment in this Commonwealth as a 90% control of both oxidized and elemental mercury emissions at EGUs.[13] There is, therefore, no basis for the Board to conclude that anything other than controls on

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[13] In fact, requiring a 90% reduction in oxidized mercury could well be *more effective* in reducing mercury deposition in Pennsylvania than a 90% reduction in total mercury. This is because a 90% total mercury reduction requirement could result in less than 90% capture of oxidized mercury. With particle-bound mercury already controlled at greater than 90%, and the approach of oxidizing elemental mercury in order to capture it, the result of a total mercury control requirement could well be more than 90% reductions in elemental and particle-bound mercury but less than 90% reductions in oxidized mercury.

oxidized mercury is needed to address the "hot spot" issue. Accordingly, only reductions in oxidized mercury (and the already achieved control of particle-bound mercury), could be justified as a reasonable exercise of the Board's discretion pursuant to the Board's authority under Sections 2 and 5 of the APCA, 35 P.S. § 4002 and § 4005(a).

2. THE BAR ON TRADING COULD CAUSE MERCURY DEPOSITION TO INCREASE AND FAILURE TO ACHIEVE THE CAMR BUDGET ALLOCATION -- THE BOARD SHOULD IMPLEMENT CAMR WITH TRADING INSTEAD

To be sure, regardless of the relevance for deposition in Pennsylvania, EPA's CAMR, promulgated under the federal CAA, imposes a total mercury allowance budget for the Commonwealth of 1.78 tons for 2010-2017 and 0.702 tons for 2018 and after. Of course, even with reductions in oxidized mercury secured, reductions in the remaining elemental mercury will be needed to achieve the overall allowance allocations for total mercury. But reducing that elemental mercury fraction of the total mercury has almost no bearing on deposition in the Commonwealth, and emissions trading is surely well-suited to trading what will amount to emissions that are part of a *global* pool. *See* NERA Report at 2. As there will be no benefit to human health or the environment for Pennsylvania to forcing EGUs to achieve that additional increment of reductions by capturing elemental mercury at units in Pennsylvania, there is no justification, let alone any compelling reason, to go beyond CAMR in the Annual Emissions Limit program of the proposed rule, either by accelerating those limits to 2015 or by restricting trading of those allowances. In fact, efforts to capture elemental mercury in order to comply with the proposed rule actually could *increase* deposition slightly in Pennsylvania. Finally, by opting out of the trading program, Pennsylvania no only imposes substantial costs on EGUs with no corresponding environmental benefit, but also jeopardizes its ability to comply with its CAMR budget.

a. THE PROPOSED RULE COULD ACTUALLY *INCREASE* MERCURY DEPOSITION IN PENNSYLVANIA

The technical reason for the potential *increase* in oxidized mercury is straightforward. Technologies such as SCR and halide injection promote the oxidation of elemental mercury so that it will become water soluble and can be removed by the very same wet scrubber and ESPs already removing the pre-existing oxidized mercury in the flue gas. *See* URS Report at 18. The scrubber and ESPs, while very good at removing that oxidized mercury at least a 90% efficiency are not perfect. *See* URS Report at 18. A small portion of the total oxidized mercury, in the range of 5-10%, may escape as emissions to the atmosphere. So, for every pound of elemental mercury that is oxidized by an SCR unit, up to perhaps one-twentieth to one-tenth of a pound of additional oxidized mercury may be emitted. This is, of course, an inconsequential amount and would not cause mercury "hot spots." But comparing scenarios with and without the addition of SCR, it is plain that there will be slightly *more* oxidized mercury at the stack outlet resulting from the effort to capture the elemental mercury. What was originally elemental mercury emitted to a global pool without affecting Pennsylvania thereby becomes a smaller amount of oxidized mercury that could deposit in Pennsylvania. Promoting that result certainly is not necessary to protect human health and the environment in the Commonwealth and may, in fact, be counterproductive.

b. THE PROPOSED RULE COULD RESULT IN INABILITY TO COMPLY WITH THE CAMR BUDGET ALLOCATION

Allowing trading is likely necessary to achieve compliance with the CAMR budget allocation for Pennsylvania. The Board must allow trading to meet its obligation to adopt rules that are compliant and consistent with regulations adopted under the federal CAA. Specifically, absent trading, given the severely limited budget for Pennsylvania so that as much as 95%-98% control of total mercury in the coal would be required in Phase 2, available technologies are likely to be simply unable to achieve that extreme level of control. Even if the proposed rule contains provisions for an alternative emissions limit "exemption" due to infeasibility, this is likely not only to involve a cumbersome and costly administrative process, but the outcome would be that the Commonwealth will not comply with its budget allocation, as total emissions will be *higher* than allowed under the federal rules, and there will be no trading option to make up the deficit.

In other words, after all of the expense and effort of going after the last increment of total mercury, with the potential even to *increase* emissions of oxidized mercury compared to using just scrubbers and ESPs, Pennsylvania would likely fall short in achieving its budget for total mercury.[14] Even assuming EPA would approve such a Pennsylvania program, that result would increase total mercury emissions, not reduce them.

As long as Pennsylvania EGUs control oxidized mercury emissions as discussed above, allowing trading for the remainder of the total mercury emissions from EGUs not only is protective of health and the environment in Pennsylvania and would save substantial costs, but is actually *necessary* to satisfy the Board's legal obligation to take action that is consistent and compliant with CAMR, fulfilling Pennsylvania's obligation with regard to national total mercury control.

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[14] This concern applies equally in 2010 (Phase I) and 2015 (Phase II) for at least two reasons. First, the Phase I CAMR allocation to Pennsylvania implies a reduction from mercury as high as 88%-90% at some EGUs. Second, control technology decisions for Phase I would have to take into account expectations in Phase II. As a result, some EGUs would likely install the technology expected to be required for Phase II during Phase I. Thus, without trading, the control costs incurred in both phases would be substantial, and the CAMR budget allocation unachievable. *See* NERA Report at 31.

II. THE BOARD HAS NOT CONSIDERED THE EXTREME AND UNJUSTIFIABLE COSTS OF MEETING THE CAMR ALLOWANCE ALLOCATIONS WITHOUT TRADING

Where, as here, the APCA does not specifically mandate regulation and the Board exercises its discretion, it must consider the economic impacts of its regulatory action. *See Rochez Bros.*, 334 A.2d at 797 n.8 (where "the Act gives the DER discretionary authority to act . . . we believe DER must consider the economic impact of its actions."). The Board's analysis of the economic impact of the Proposed Rule is fundamentally flawed, because it disregards EPA's draconian under-allocation of allowances to Pennsylvania under CAMR based on EGUs burning bituminous coal. The Annual Emissions Limit that requires meeting these allowances without trading effectively requires 88 -90%capture of the total mercury in the coal in Phase 1 and 95-98%in Phase 2. This renders superfluous the less stringent Emissions Standards on which the Board based its cost assessment. Meeting such Annual Emissions Limits will be extremely costly if not infeasible.

In the Preamble, the Board claims that relatively modest costs will be incurred for compliance with the Pennsylvania rule. The Board asserts that the cost of complying with the Pennsylvania rule for Phase 1 would be no more than the cost of complying with CAMR and that the cost of complying with Phase 2 would only be $2,000,000 more than buying allowances under CAMR. The Board's conclusions are based on the assumption that the majority of EGUs in the Commonwealth will be able to comply with both phases of the Proposed Rule using the scrubber and SCR technology used to comply with CAIR. Preamble at 3193. This is not correct.

As discussed above in describing CAMR, EPA established the budget allocations for the states, including Pennsylvania, based on each state's share of total national heat input to coal-fired EGUs in their state, but with an important adjustment to increase the allocation for states with EGUs burning sub-bituminous coal and lignite and a corresponding decrease in the allocation for EGUs burning bituminous coal, such as in Pennsylvania. As a result, the budget allocation for Pennsylvania, once allowances for new development are reserved, results in a requirement that EGUs such as PPL's achieve 88% (Phase 1) and 95-98% (Phase 2) reductions in total mercury in the coal. The Board's cost estimates simply fail to recognize this fact and are, therefore, inaccurate.

Achieving these levels of reductions at each plant is a great challenge and will be very costly. A proper economic analysis shows that compliance costs for the Pennsylvania rule will be extraordinary. The Board claims that the *total* cost of complying with Phase 2 of the Proposed Rule will be $16.7 million. Preamble at 3193. That estimate erroneously assumes that the technology needed to comply with CAIR will also satisfy Phase 2 requirements. However, the technology needed to comply with CAIR will not obtain the 95 – 98% reductions necessary to achieve the Annual Emissions Limit. URS Report at 7, 25. In fact, the cost of meeting the Annual Emission Limit for just *one* unit will be more that double the cost that the Department estimated for *all* EGUs. *See* URS Report at 25-29.

Essentially admitting that it under-estimated the cost of controlling total mercury from bituminous coal and its budget for Pennsylvania is an under-allocation relative to other states, EPA has projected that it will not be cost-effective for EGUs in Pennsylvania to make the required reductions themselves but rather they would be net purchasers of allowances under CAMR with trading. In other words, EPA projects that its budget allocations for total mercury will cause Pennsylvania EGUs to fund emissions reductions in other states, some of which received budget allocations *greater than their current emissions*. EPA thus has projected that EGUs in other states have greater budgets relative to their cost of reducing emissions and will be net sellers of allowances, in effect making their reductions funded in part by out-of-state EGUs. One could complain that the budget allocations are distributively unfair, effectively taxing Pennsylvania EGUs to pay for reductions elsewhere, and DEP has indeed made just this complaint to EPA. *See* Letter dated June 29, 2004 from Nicholas A. DiPasquale, Deputy Secretary for Air, Recycling and Radiation Protection to U.S. EPA Docket ID No. OAR-2002-0056 (". . . the proposed rules establish control requirements that improperly sub-categorize by coal type and establish a bias against bituminous coal."); "Comments Submitted By: The States of New Jersey . . . Pennsylvania . . . and Wisconsin In Re Reconsideration of [CAMR]", December 19, 2005, p. 29.

But at least the CAMR allocations are *feasible, with trading*. A key benefit of trading is that it protects against the cost ramifications of just such misallocations, by setting an upper bound on the cost of compliance at the prices of allowances. *See* NERA Report at 30 (Indeed, it is even *feasible* to require 100% or greater emissions reductions from Pennsylvania EGUs *with trading*, as that would simply amount to a requirement that the EGUs buy more allowances. Obviously, reductions greater than 100% would be impossible for the EGUs to achieve without trading.) Prohibiting trading, however, would be a serious setback on four different levels: (1) the inability to trade exacerbates the fundamental unfairness of the CAMR budget allocation to Pennsylvania; (2) the reductions will be even more costly without trading; (3) the required reductions are potentially *infeasible* with available technologies; and (4) all of this will be for naught as no changes to mercury deposition will be observed.

Without trading, there is *no upper bound* on the costs that might be expended to achieve compliance with the allowance allocation. *See* NERA Report at 30. Without trading, many EGUs through out Pennsylvania will have to install expensive add-on control technologies at enormous costs.. *See* URS Report at 7, 10, 25. As noted above, these additional controls will not produce any meaningful further reductions in oxidized or particle-bound mercury emissions and, thus, will have no beneficial effect on mercury deposition in Pennsylvania. Deprived of access to the national trading program, Pennsylvania EGUs will be required to incur enormous costs, on the order of $40 million to $75 million per unit in Phase 2, with no corresponding environmental benefit. Thus a proper cost-benefit analysis reveals that the Proposed Rule fails to satisfy the Legislative policy directive in section 2 of the APCA, 35 P.S. 4002.

III. THE PROPOSED RULE EXACERBATES THE NEGATIVE IMPACT OF CAMR ON BITUMINOUS COAL

DEP has repeatedly criticized the EPA rule for imposing an unfair burden on EGUs burning bituminous coal. *See*, Letter from Secretary McGinty to U.S. EPA Docket ID OAR-2002-0056 (January 3, 2005) ("One of the most troublesome aspects of EPA's proposed mercury control options is the unfairly disproportionate burden on eastern coal."). However, the Proposed Rule worsens rather than lessens the burden on bituminous coal.

In the Preamble and in testimony, the Board and Department have suggested that 90% control of total mercury emissions along with the presumptive technology will serve to preserve market share for bituminous coal and offset the perceived inequities in the CAMR allocation. The Department has asserted that the proposed rule "Preserves market share for bituminous coal by presuming compliance for electric generating units that burn 100% bituminous with advanced air control technologies." *See* Testimony of Secretary McGinty before the Senate Environment Resources and Energy Committee (April 25, 2006). However, the Proposed Rule does not achieve this laudable goal. The presumptive technology upon which the Board and Department rely only addresses the Emission Standards and does not address the Annual Emission Limit. As noted elsewhere in these comments, the CAMR-based Annual Emission Limit must also be met and under the Board's rule, must be met without trading. In fact, 80% and 90% control of total mercury emissions will not achieve compliance with the CAMR caps and reductions on the order of 88 % and 95% will be required in Phases 1 and 2. The feasibility of achieving these reductions is questionable and the costs are enormous. *See*, URS Report at 4, 7, 25. Regardless of the Board's and Department's intentions, the Proposed Rule with its presumptive technologies will do nothing to benefit bituminous coal as long as EGUs are required to meet the CAMR budget through controls only and trading is prohibited.

Rather than benefiting bituminous coal, the Proposed Rule exacerbates the situation. Regardless of the inequities of the CAMR budget allocations for bituminous coal, the EPA rule would allow for trading, which limits the impacts of the very tight budget. The cost of compliance is limited to the price of allowances. The Proposed Rule, to the contrary, requires that the budget be met entirely through emission reductions at each Pennsylvania EGU, whatever the cost. There is no justification for the Pennsylvania rule as a mechanism to preserve the market share of bituminous coal, as it does just the opposite. The Proposed Rule will increase costs for these EGUs, and create the very real possibility that units in Pennsylvania that cannot feasibly achieve or cannot economically justify the additional required controls to meet the CAMR-based budget will have to curtail generation or shut down. When that capacity is transferred to facilities in other states, the market share of Pennsylvania bituminous coal is, likewise, threatened.

If the Proposed Rule were truly designed to preserve the market for bituminous coal, the Board would recognize that the presumptive technologies will obtain reductions of 90% or more for oxidized and particle bound mercury; that EGUs burning bituminous coal produce relatively lower amounts of elemental mercury; and, that requiring additional add on controls to address elemental mercury produces no benefit for Pennsylvania and actually aggravates the inequities that the Department has raised concerning CAMR.

IV. THE PROPOSED RULE IS INCONSISTENT WITH THE REQUIREMENTS OF THE APCA FOR THE BOARD TO ADOPT EMISSION STANDARDS FOR A HAZARDOUS AIR POLLUTANT

The APCA specifically authorizes the Board to regulate hazardous air pollutants ("HAPs"), subject to several provisos. *See* 35 P.S. § 4006.6. First, the Board has general authority to establish standards for HAPs for sources not included on the list of sources for HAP regulation under Section 112(c) of the federal CAA. 35 P.S. § 4006.6(a). Second, the Board may adopt a health risk-based standard when needed to protect the public health. To do so, however, the Board must provide a specific rationale, considering criteria such as public health significance and commercially available methods and costs to reduce such risks, as described in Section 112(f)(1) of the CAA. *See* 35 P.S. § 4006.6(d)(1). Third, the Board may not establish a more stringent standard for HAPs from existing sources than EPA establishes, unless justified as a health risk-based standard. 35 P.S. § 4006.6(a) ("The [Board] may not establish a more stringent performance or emission standard for [HAPs] from existing sources, except as provided in subsection (d)."). Finally, if EPA has not adopted a standard to control HAPs from a category of sources in accordance with the CAA schedule (under Section 112(c) of the CAA), DEP may establish an emission standard for a category of sources on a case-by-case basis for such sources, but that standard must be equivalent to the standard that would apply if EPA were to adopt a standard under Section 112 of the CAA. 35 P.S. § 4006.6(b). The Proposed Rule does not meet these requirements.

A. THE PROPOSED RULE IS INCONSISTENT WITH THE REQUIREMENTS FOR THE ADOPTION OF HEALTH RISK-BASED EMISSION STANDARDS

The Board apparently believes that the proposed mercury rule is necessary to protect the public health and environment and that CAMR will not accomplish that goal adequately. Preamble at 3185, 3189, 3192. Thus, the Board proposes to adopt a health risk-based regulation. If the Board or Department wishes to promulgate a health-risk based standard for a hazardous air pollutant they must follow the procedure set forth in section 6.6(d)(1) of the APCA, 35 P.S. 4006.6(d)(1). These requirements apply on their face without limitation and regardless of what EPA may have done or not done to establish standards for sources under section 112 of the Clean Air Act. Section 6.6(d)(1) applies *anytime* the Board or Department seek to establish a health-risk based standard, such as the Proposed Rule, and do no depend on whether EPA has established standards under Section 112. Indeed, sub-section 6.6(d)(1) applies even if the Board is not seeking to be (or is authorized to be) more stringent than EPA.

The Board has not set forth a sufficient rationale for adopting a health risk-based standard meeting the requirements of the APCA, 35 P.S. 4006.6(d)(1). Despite the many conclusory statements regarding an alleged public health risk of "hot spots" due to mercury deposition in the Preamble, there is no specific analysis, indicating that the Department has established that emissions of total mercury create hot spots. There are numerous statements that "hot spots" "may" or "could" create public health issues (Preamble at 3189) but no analysis to support these statements and certainly no analysis of the appropriate way to address this specific risk. Nowhere does the Board identify the methods used for calculating the risk to public health – rather than just baldly asserting that it exists. Nor does the Board offer any analysis of the methods to reduce such risks, the costs or the cost-effectiveness of such methods. The Board offers no evidence or analysis that "hot spots" even exist or present a public health threat. In fact, after alleging that oxidized mercury emissions are the cause of "hot spots" the Board does nothing to evaluate the public health implication of oxidized mercury emissions or to evaluate the "technologically and commercially available methods and costs" of reducing the risks from oxidized emissions alone. The Preamble fails to demonstrate that the Board or Department conducted an analysis that considered the criteria set forth in section 112(f) of the Clean Air Act, as required by 35 P.S. § 4006.6 (d)(1).

Were the Board to undertake such a careful analysis, it would reach the same conclusions PPL describes above. Even if hot spots of public health concern might exist (and PPL has not itself specifically investigated that issue), the only potential contribution to mercury deposition in Pennsylvania is from oxidized mercury. There would be no justification for a health risk-based emission standard for total mercury, or constraining the ability to trade allowances for total mercury under CAMR. The Board should conduct such an analysis as required under the APCA and should acknowledge these conclusions.

B. THE PROPOSED RULE DOES NOT COMPLY WITH REQUIREMENTS APPLICABLE WHERE EPA HAS NOT ADOPTED A STANDARD

The Board maintains that it may adopt emission standards for mercury for EGUs without the APCA constraint against adopting a "more stringent" standard because EPA has not adopted a standard for mercury under Section 112. The Department and the Board declare that the "no more stringent than" provisions of Section 6.6(a) of APCA do not constrain their authority. Preamble at 3187. The Board also notes that it may "establish emission standards for source categories which are not included on the list of source categories established under Section 112(c) of the CAA." *Id.* The Board misconstrues the APCA.

The language relied upon by the Board allows it to establish standards for source categories where EPA has not done so. It does not state whether or not that standard can be more stringent. Moreover, the prohibition against being more stringent found elsewhere in Section 6.6(a) does not specify that the EPA standard must be for a source category established under Section 112(c) of the CAA. It simply states that the Board may not establish a more stringent standard for hazardous air pollutants except as authorized in subsection (d) without any reference to Section 112. This understanding of the Legislature's intent also makes common sense. The Board should justify any decision that health risks warrant greater stringency than the EPA standards for hazardous air pollutants, regardless of what statutory provision of the federal Clean Air Act EPA relies upon to promulgate those standards. The Board and Department strongly assert that mercury is a hazardous air pollutant, thus the Board may only be more stringent than EPA if it complies with Section 6.6(d). As noted in the preceding section of these comments, the Board has failed to comply with Section 6.6(d)(1).

The Board's authority to promulgate a standard in the case where EPA has not promulgated such a standard is further addressed in Section 6.6(b). The Board is authorized to adopt a standard for a category of sources, but must adopt a standard that would be the same as the standard that would have been promulgated by EPA under Section 112 of the Clean Air Act. Nothing in the Preamble or in the proceeding of the Department or the Board to date shows that the requirements of Section 112 of the CAA standards were considered. The requirement to promulgate the same standard as EPA would have promulgated is entirely consistent with the Section 6.6(a) directive that the Board may not be more stringent than EPA unless justified under Section 6.6(d).

As discussed above, even assuming hot-spots are a concern in Pennsylvania, there is no justification for the Board to go further than EPA to impose more stringent requirements for total mercury, rather than adopting as an overlay on EPA's CAMR requirements for oxidized mercury that might deposit in Pennsylvania. Moreover, scrubbers are equally or more effective than any other technology for control of oxidized mercury emissions, achieving 90 percent or greater capture of oxidized mercury. *See* URS Report at 6, 14. Even if viewed as a technology-based standard (such as under Section 112), this is all the Board can justify to address mercury deposition in Pennsylvania.

CONCLUSION

For the foregoing reasons, the Board should not adopt the Proposed Rule as published. Rather, the Board should first properly analyze whether hot spots are a legitimate public health concern for Pennsylvania. If so, then the Board should determine whether mercury reductions expected to be made in Pennsylvania under CAMR and CAIR would be sufficient to address the concern. If the Board concludes that state-specific regulation is required, then the Board should structure the rule as follows. First, the Board should implement CAMR, with unrestricted trading of allowances, to comply with the federal budget allocation for *total* mercury. This will ensure that Pennsylvania fulfills its federal obligation in a cost-effective manner that is suitable for controlling elemental mercury as a global pollutant. Second, the Board should adopt an overlay on CAMR to address state-specific environmental concerns. Specifically, the Board should adopt requirements that EGUs achieve a specified level of control of *oxidized* mercury at each EGU.