**Technical Support Document**
**for the**
**Clean Air Mercury Rule**
**Notice of Final Rulemaking**

# State and Indian Country Emissions Budgets

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**Prepared by**
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## State and Tribal Emissions Budgets

This technical support document (TSD) provides a description of the methodology and data sources used in the calculation of State and Tribal emission budgets for mercury (Hg) under the final Clean Air Mercury Rule (CAMR).

This TSD outlines the following:

- Rationale for coal adjustment factors used in determining State and Tribal emission budgets;
- Methodology for determining the State and Tribal emission budgets;
- State and Tribal emissions budgets for 2010 and 2015; and
- Calculations of unit allocations used to derive State and Tribal emission budgets.

## Overview

As discussed in the final CAMR, the trading program establishes, for affected coal-fired utility units, a Phase I Hg cap of 38 tons in starting in 2010 and a Phase II cap of 15 tons starting in 2018. For the final rule, these national caps are apportioned among the 50 States, two Tribes, and the District of Columbia.

As proposed, EPA is finalizing a formula to be used to develop budgets for each state and Tribes for 2010 and 2018. That formula is, in essence, the sum of the hypothetical allocations to each affected Utility Unit in the State or Tribe, and that allocation, in turn, is based on the proportionate share of their baseline heat input to total heat input of all affected units. For purposes of this hypothetical allocation of the allowances, each unit's baseline heat input is adjusted to reflect the ranks of coal combusted by the unit during the baseline period. While the formula determines the States' or Tribes' allocation budgets, each State or Tribe is given discretion on how to distribute the allocations within a State or Tribe.

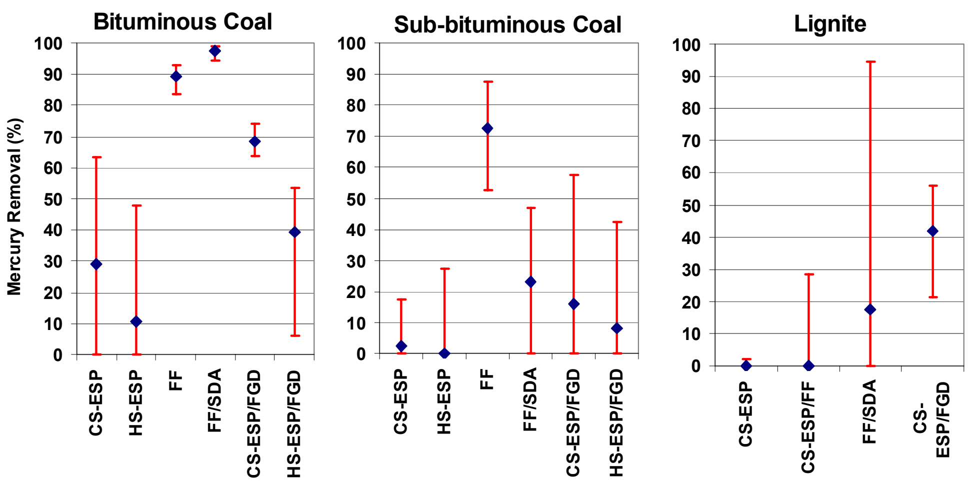
As proposed, coal adjustment factors of 1 for bituminous, 1.25 for subbituminous, and 3 for lignite coals are being finalized for use in the development of unit allocations for affected coal-fired Utility Units.

## Rationale For Coal Adjustment Factors

As discussed above, adjustment factors of 1.0 for bituminous, 1.25 for subbituminous, and 3.0 for lignite coals are being used for the final CAMR. The allocation methodology takes into account the different levels of mercury control that lignite, bituminous, and subbituminous coals can achieve. Specifically, the adjustment factors are based on the expectation that, for different coal ranks, mercury reacts differently to NOx and $SO_2$ control equipment. EPA examined several data sources to develop the allocation adjustment factors, and considers the factors to be appropriate numbers based on the data available.

The conclusion that mercury in each of the coals reacts differently to NOx and $SO_2$ control equipment was based on information collected in EPA's 1999 Mercury Information Collection Request. According to the 1999 ICR data, the existing air pollution control technologies used on coal-fired utility boilers exhibit average levels of mercury control that range from 0 to 98 percent. The amount of mercury capture varied by given control technology configuration (e.g. cold-side ESP or cold-side ESP and wet scrubber) and by coal grade. As presented in Figure 1, bituminous coal achieved the best capture (ranging between 10% and 98%), subbituminous the next best capture (ranging between 0% and 72%), and lignite the lowest capture (ranging between 0 and 44%).[1]

**Figure 1: Mercury Removal Rates Measured for Various coal types and Control Figurations (from EPA ICR data, 1999)**




The 1999 Hg ICR emission test data and other more recent testing conducted by EPA, DOE, and industry participants has provided a better understanding of Hg emissions and their capture in pollution control devices. Mercury speciates into three basic forms, ionic, elemental, and particulate (particulate represents a small portion of total emissions). In general, ionic Hg compounds are more readily adsorbed than elemental Hg and the presence of chlorine compounds (which tend to be higher for bituminous coals) results in increased ionic mercury. Overall the 1999 Hg ICR data revealed higher levels of Hg capture for bituminous coal-fired plants as compared to subbituminous and lignite coal-fired plants and a significant capture of ionic Hg in wet $SO_2$ scrubbers. Additional Hg testing indicates that for bituminous coals SCR has the ability to convert elemental Hg to ionic Hg and thus allow easier capture in a wet scrubber. The ICR also collected coal property data for the year 1999, including quarterly analysis of the mercury and chlorine content of coal from all electric power generating plants.

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[1] For more discussion see *Control of Emissions from Coal-Fired Electric Utility Boilers: An Update*, EPA/Office of Research and Development, March 2005, in docket.

Table 1 shows the mercury and chlorine content of coal by type[2].

**Table 1: 1999 Characteristics of Coals Burned in U.S. Power Plants**

| | Hg Content (lb/TBtu) | | Chlorine Content (ppm dry) | |
|---|---|---|---|---|
| | **Range** | **Average** | **Range** | **Average** |
| Bituminous | 0.04-103.81 | 8.59 | 48-2730 | 1033 |
| Subbituminous | 0.39-71.08 | 5.74 | 51-1143 | 158 |
| Lignite | 0.93-75.06 | 10.54 | 133-233 | 188 |

The Hg ICR data lead to the calculation of a national Hg emissions estimate of 48 tons in 1999. Tables 2 provides that estimate by coal type and by coal capacity. Examining Hg emissions by coal-fired capacity indicates that lower rank coals have more emissions per given capacity, which is supported by ICR data that indicates less capture by given control technology configuration. As presented in Table 2, subbituminous coals have over 1.25 times the emissions per capacity compared to bituminous coals, and lignite coals have close to 3 times the emissions per capacity compared to bituminous coals.

**Table 2: 1999 Mercury Emissions and Capacity by Coal Type**

| | Emissions (tons) | Capacity (GW) | Emission per capacity (lb/MW) |
|---|---|---|---|
| Bituminous | 28.2 | 228 | 0.25 |
| Subbituminous | 15.9 | 86.528 | 0.37 |
| Lignite | 4.4 | 13.462 | 0.65 |

In conclusion, to develop allocation ratios, EPA balanced the above factors: (1) data on mercury capture by control figuration and coal type, (2) data on coal characteristics impacting Hg capture, and (3) Hg emissions by capacity. EPA believes the allocation adjustment ratios recognize that subbituminous and lignite coals have the lowest mercury capture with existing technologies, represent more emissions per capacity, and in the case of lignite also have higher mercury coal content.

It should also be noted that these allocation adjustment factors should not impact the achievement of the specific environmental goal or impact the overall efficiency of the cap-and-trade program. Allowance allocation decisions in a cap-and-trade program raise essentially

[2] Control of Mercury Emissions from Coal-Fired Electric Utility Boilers: Interim Report, U.S. EPA, EPA-600/R-01-109, April 2002.

distributional issues, as economic forces are expected to result in economically least cost and environmentally similar outcomes regardless of the manner in which allowances are initially distributed. Consequently in the final CAMR, EPA is providing States with flexibility in developing their allocation approach.

**Methodology for Determining the State and Tribal Emission Budgets**

The final CAMR establishes the total number of tons for the Budget Trading Program within a specific State or Tribe for Phase I and Phase II. Hypothetical unit level allocations were derived and those unit allocations at the state level were added to develop a State or Tribe emission budget. The State and Tribal Budgets are presented in Table 3 below.

Hypothetical unit allocations were determined by adjusting a baseline heat input. That baseline heat input was determined using the average of the three highest heat inputs for each unit of the period 1998 to 2002. In order to adjust the heat input based on coal type, coal usage patterns were determined from the 1999 ICR data. The following section of the TSD describes in detail the databases and other information EPA used to derive the heat input and coal use data to derive hypothetical unit allocations.

To calculate hypothetical units allocations, EPA first multiplied the baseline heat input for each unit by the adjustment factor and then added this number to develop a total adjusted baseline heat input. Next, the hypothetical unit allocation was determined by multiplying the Hg cap by the ratio of the unit's adjusted baseline heat input to the total adjusted baseline heat input. State and Tribal budgets were calculated by summing the hypothetical allocations to each unit in the State or Tribe. While the formula determines the States' or Tribes' emission budgets, each State is given discretion on how to distribute the allocations within a State or Tribe.

EPA received comments from Tribes noting that only States currently receive allowances under the proposal, despite unit allocations being made to Tribal sources, and requesting that Tribes be accommodated into the cap-and-trade program. Because under CAA authority Tribes have jurisdiction over sources on Tribal land, EPA agrees with the commenters that these Tribal sources require the need for establishing Tribal budgets for existing sources in the final CAMR. In the final rule, EPA is establishing two Tribal budgets for three existing coal-fired Utility Units on Tribal lands. These are Navajo Generating Station (Salt River Project; Page, AZ), Bonanza Power Plant (Deseret Generation and Transmission Cooperative; Vernal, UT), and Four Corners Power Plant (Salt River Project/Arizona Public Service; Fruitland, NM). Navajo Generating Station and Four Corners Power Plant are on lands belonging to Navajo Nation, and Bonanza Power Plant is located on the Uintah and Ouray Reservation of the Ute Indian Tribe. Therefore, in addition to the 50 State budgets and the District of Columbia, the final CAMR also contains budgets for the Navajo and Ute Indian Tribes. In the proposed rule, these three units on Tribal lands were included in the State budgets for Arizona, Utah, and New Mexico. The proposed emissions budgets for Arizona, Utah, and New Mexico are adjusted to reflect the movement of sources to Tribal emission budgets.

### Table 3: State and Tribal emissions budgets for 2010 and 2018

| State | Budget (tons) | |
|---|---|---|
| | 2010-2017 | 2018 and thereafter |
| Alaska | 0.005 | 0.002 |
| Alabama | 1.289 | 0.509 |
| Arkansas | 0.516 | 0.204 |
| Arizona | 0.454 | 0.179 |
| California | 0.041 | 0.016 |
| Colorado | 0.706 | 0.279 |
| Connecticut | 0.053 | 0.021 |
| Delaware | 0.072 | 0.028 |
| District of Columbia | 0 | 0 |
| Florida | 1.233 | 0.487 |
| Georgia | 1.227 | 0.484 |
| Hawaii | 0.024 | 0.009 |
| Idaho | 0 | 0 |
| Iowa | 0.727 | 0.287 |
| Illinois | 1.594 | 0.629 |
| Indiana | 2.098 | 0.828 |
| Kansas | 0.723 | 0.285 |
| Kentucky | 1.525 | 0.602 |
| Louisiana | 0.601 | 0.237 |
| Massachusetts | 0.172 | 0.068 |
| Maryland | 0.490 | 0.193 |
| Maine | 0.001 | 0.001 |
| Michigan | 1.303 | 0.514 |
| Minnesota | 0.695 | 0.274 |
| Missouri | 1.393 | 0.550 |
| Mississippi | 0.291 | 0.115 |
| Montana | 0.378 | 0.149 |
| Navajo Nation | 0.601 | 0.237 |
| North Carolina | 1.133 | 0.447 |
| North Dakota | 1.564 | 0.617 |
| Nebraska | 0.421 | 0.166 |
| New Hampshire | 0.063 | 0.025 |
| New Jersey | 0.153 | 0.060 |
| New Mexico | 0.299 | 0.118 |
| Nevada | 0.285 | 0.112 |
| New York | 0.393 | 0.155 |
| Ohio | 2.056 | 0.812 |
| Okalahoma | 0.721 | 0.285 |
| Oregon | 0.076 | 0.030 |
| Pennsylvania | 1.780 | 0.702 |
| Rhode Island | 0 | 0 |
| South Carolina | 0.580 | 0.229 |
| South Dakota | 0.072 | 0.029 |
| Tennessee | 0.944 | 0.373 |

| | | |
|---|---|---|
| Texas | 4.657 | 1.838 |
| Utah | 0.506 | 0.200 |
| Ute Indian Tribe | 0.060 | 0.024 |
| Virginia | 0.592 | 0.234 |
| Vermont | 0 | 0 |
| Washington | 0.198 | 0.078 |
| Wisconsin | 0.890 | 0.351 |
| West Virginia | 1.394 | 0.550 |
| Wyoming | 0.952 | 0.376 |

**Calculations of Unit and State And Tribal Mercury Allocations**

This section of the TSD describes mercury (Hg) allocation calculations at the unit level. The calculations are provided in an electronic spreadsheet file: Final CAMR Unit Hg Allocations.xls, which contains the unit level allocations.

*Methodology*

Affected Units

The affected unit population for the allocation calculations was based on the 1999 Hg ICR inventory, supplemented by EPA Clean Air Market Division's monitoring plan database. The Hg ICR surveyed coal-fired electric generating units (EGUs). The survey defined an EGU as a coal-fired unit serving a generator with a nameplate capacity greater than 25 MW that produces electricity for sale, except for a cogeneration unit that produces electricity for sale equal to less than one-third of the potential electrical output of the generator. The EGU definition is similar to the Acid Rain definition in 40 CFR Part 72, except that there are additional exemptions from the Acid Rain Program for certain small independent power producers. The Hg ICR inventory includes both Acid Rain and non-Acid Rain units.

Acid Rain Program units that burned coal based on monitoring plan information, and that were not in the Hg ICR inventory, were added to the affected unit population for the allocation calculations. This included units that were in existence when the Hg ICR was conducted, and new coal-fired Acid Rain units that have come online since the 1999 Hg ICR.

Baseline Heat Input

There were three approaches used to first calculate the baseline heat input, depending on the availability of heat input data:

**Acid Rain Units.** Annual heat input information is reported by Acid Rain units and is available in the Acid Rain database. The highest three annual heat input years in the 1998 - 2002 period were identified and heat inputs averaged to first calculate an "unadjusted baseline."

In some cases, units that had become subject to the Acid Rain Program later in the period had less than three years of data. In those cases either a two year average of annual Acid Rain heat input was used, or one year of Acid Rain heat input was used. Table 4 identifies these units, and documents how the unadjusted baselines were calculated for these special situations.

**Table 4: Existing Acid Rain Units with Less Than Three Years of Heat Input Data**

| State | Plant | ORIS Code | Unit ID | Heat Input Used in Calculation | Comment |
|---|---|---|---|---|---|
| MN | Taconite Harbor Energy Center | 10075 | 1 | 2002 | Acid Rain HI for 2002. No Hg ICR data. |
| MN | Taconite Harbor Energy Center | 10075 | 2 | 2002 | |
| MN | Taconite Harbor Energy Center | 10075 | 3 | 2002 | |
| NC | Elizabethtown Power | 10380 | Unit 1 | 2 Year Average (2001, 2002) | Acid Rain HI for 2001 and 2002. No Hg ICR data. |
| NC | Elizabethtown Power | 10380 | Unit 2 | 2 Year Average (2001, 2002) | |
| NC | Lumberton Power | 10382 | Unit 1 | 2 Year Average (2001, 2002) | Acid Rain HI for 2001 and 2002. No Hg ICR data. |
| NC | Lumberton Power | 10382 | Unit 2 | 2 Year Average (2001, 2002) | |
| PA | Foster Wheeler Mt Carmel | 10343 | SG-101 | 2002 | Acid Rain HI for 2002. 2002 Acid Rain HI comparable to 1999 Hg ICR. |
| VA | Hopewell Power Station | 10071 | 1 | 2 Year Average (2001, 2002) | Acid Rain HI for 2001 and 2002. 2002 Acid Rain HI significantly less than 2001. Two year average, however, is still higher than 1999 Hg ICR data. |
| VA | Hopewell Power Station | 10071 | 2 | 2 Year Average (2001, 2002) | |
| VA | Altavista Power Station | 10773 | 1 | 2 Year Average (2001, 2002) | Acid Rain HI for 2001 and 2002. Acid Rain HI significantly higher than 1999 Hg ICR data. |
| VA | Altavista Power Station | 10773 | 2 | 2 Year Average (2001, 2002) | |
| VA | Southampton Power Station | 10774 | 1 | 2 Year Average (2001, 2002) | Acid Rain HI for 2001 and 2002. Acid Rain HI significantly higher than 1999 Hg ICR data. |
| VA | Southampton Power Station | 10774 | 2 | 2 Year Average (2001, 2002) | |

**New Acid Rain Units.** There were five new coal fired Acid Rain units which came on line in 2001 and 2002. The 2002 heat input information was used for these units, prorated based on the first month of reported data. For four of the units the heat input was prorated for 8 months of operation, and for one unit a full year (see Table 5).

**Table 5: New (Operation after 1999) Acid Rain Coal Fired Units**

| State | Plant | ORIS Code | Unit ID | CAMD On-Line Date | Heat Input Used and Months of Operation |
|---|---|---|---|---|---|
| FL | Northside | 667 | 0.04 | 2/19/2001 | 2002, 8 months |
| FL | Northside | 667 | 0.08 | 8/1/2002 | 2002, 8 months |
| MO | Hawthorn | 2079 | 0.208 | 5/11/2001 | 2002, 12 months |
| MS | Red Hills Generation Facility | 55076 | AA001 | 2/14/2001 | 2002, 8 months |
| MS | Red Hills Generation Facility | 55076 | AA002 | 2/14/2001 | 2002, 8 months |

**Non-Acid Rain Units**. Non-Acid Rain units in the Hg ICR inventory do not uniformly report annual heat input to Clean Air Market Division (some OTC $NO_x$ Budget Program units may have reported ozone season heat input for 1999 - 2002). Baseline heat input information was collected by the Hg ICR for 1999. The fuel use and heat content data from the ICR were used to calculate 1999 annual heat input, and this single year was used as the baseline heat input. In some cases the Hg ICR fuel information was for multiple units. In those cases the total heat input was divided evenly between the units.

EPA updated the heat input data for 1 plant based on commenter input. EPA data was missing heat input for the AES Warrior Run plant in Maryland for the years 1998-2001. The data submitted by the commenter is highlighted in the heat input data spreadsheet available in the docket.

Adjusted Baseline Heat Input

Once a baseline heat input was calculated for the unit, it was adjusted for the specific coal type. Allocation calculations were performed based on coal adjustment factors which are shown in Table 6 below. The adjustment factors for all units were based on the type and amount of heat input from the different coal types each unit burned in one year, 1999. These data were taken from the Hg ICR information.

**Table 6: Coal Type Adjustment Factors**

| Coal Type | Factor |
|---|---|
| Bituminous, Anthracite, Waste Coal (also Petroleum Coke and Tires)[1] | 1 |
| Subbituminous | 1.25 |
| Lignite | 3 |

[1] Petroleum Coke and Tires are not coals, but were included in the Hg ICR data and the adjustment factor calculation.

Units which did not have Hg ICR coal type information should be assigned the bituminous factor. These included the five new units in Table 5, five existing Hg ICR units identified in Table 7, and Acid Rain units that were not in the Hg ICR inventory listed in Table 8.

An exception was also made for a number of units in the Hg ICR which are identified as gas-fired in the Acid Rain database. The Hg ICR had no coal data for these units, so an adjustment factor of zero was applied to the Acid Rain heat input (so that these units would receive no allocation). Also a coal fired Hg ICR unit which was destroyed in an explosion after1999, Hawthorn unit 5 in Missouri, received an adjustment factor of zero (unit is was rebuilt and is reflected as new in Table 5). These units are listed in Table 9.

Hg Allocations

While hypothetical unit allocations were used to determine the States' allocation budgets, each State is given discretion on how to distribute the allocations within a State. Hypothetical mercury allocations were calculated for each unit under a Hg cap of 38 tons and 15 tons per year. The unit allocation was determined by multiplying the Hg cap by the ratio of the unit's adjusted baseline heat input to total adjusted baseline heat input. State allocations were calculated by summing the allocations to each unit in the State (see Table 3).

**Table 7: Hg ICR Existing Coal Fired Units without Hg ICR Coal Type Information**

| State | Plant | ORIS Code | Unit |
|---|---|---|---|
| GA | Arkwright | 699 | 1 |
| KY | R D Green | 6639 | G1 |
| KY | R D Green | 6639 | G2 |
| MN | Black Dog | 1904 | 1 |
| NV | Reid Garner | 2234 | 4 |

**Table 8: Acid Rain, Non-Hg ICR, Existing Coal Fired Units without Hg ICR Coal Type Information**

| State | Plant | ORIS Code | Unit ID |
|---|---|---|---|
| IA | Dubuque | 1046 | 6 |
| IA | Lansing | 1047 | 1 |

| | | | |
|---|---|---|---|
| IA | Lansing | 1047 | 2 |
| IA | Pella | 1175 | 6 |
| IA | Pella | 1175 | 7 |
| IA | Sixth Street | 1058 | 2 |
| IA | Sixth Street | 1058 | 3 |
| IA | Sixth Street | 1058 | 4 |
| IA | Sixth Street | 1058 | 5 |
| KY | Green River | 1357 | 1 |
| KY | Green River | 1357 | 2 |
| KY | Green River | 1357 | 3 |
| MI | Presque Isle | 1769 | 1 |
| MI | Wyandotte | 1866 | 7 |
| MI | Wyandotte | 1866 | 8 |
| MN | High Bridge | 1912 | 3 |
| MN | High Bridge | 1912 | 4 |
| MN | Taconite Harbor Energy Center | 10075 | 1 |
| MN | Taconite Harbor Energy Center | 10075 | 2 |
| MN | Taconite Harbor Energy Center | 10075 | 3 |
| MO | Columbia | 2123 | 6 |
| MO | Columbia | 2123 | 7 |
| NC | Elizabethtown Power | 10380 | UNIT1 |
| NC | Elizabethtown Power | 10380 | UNIT2 |
| NC | Lumberton Power | 10382 | UNIT1 |
| NC | Lumberton Power | 10382 | UNIT2 |
| NY | S A Carlson | 2682 | 10 |
| NY | S A Carlson | 2682 | 11 |
| NY | S A Carlson | 2682 | 12 |
| NY | S A Carlson | 2682 | 9 |
| NY | WPS Empire State, Inc Niagara Falls | 50202 | 1 |
| WI | Alma | 4140 | B1 |
| WI | Alma | 4140 | B2 |
| WI | Alma | 4140 | B3 |
| WI | Blunt Street | 3992 | 7 |
| WI | Manitowoc | 4125 | 6 |
| WI | Manitowoc | 4125 | 7 |
| WI | Manitowoc | 4125 | 8 |
| WI | Stoneman | 4146 | B1 |
| WI | Stoneman | 4146 | B2 |

**Table 9: Hg ICR Units Not Included in the Allocation Calculation**

| State | Plant | ORIS Code | Unit ID | Comment |
|---|---|---|---|---|
| KS | Kaw | 1294 | 1 | Natural Gas Fired Unit |
| KS | Kaw | 1294 | 3 | Natural Gas Fired Unit |
| MI | Conners Creek | 1726 | 15 | Natural Gas Fired Unit |
| MI | Conners Creek | 1726 | 16 | Natural Gas Fired Unit |
| MI | Conners Creek | 1726 | 17 | Natural Gas Fired Unit |
| MI | Conners Creek | 1726 | 18 | Natural Gas Fired Unit |
| MO | Hawthorn | 2079 | 5 | Unit Destroyed in 1999 |