Memorandum

TO: Bill Maxwell, U.S. Environmental Protection Agency, OAQPS (C439-01)

FROM: Jeffrey Cole, RTI International

DATE: December 2003

SUBJECT: MACT Floor Analysis for Coal- and Oil-Fired Electric Utility Steam Generating Units National Emission Standards for Hazardous Air Pollutants

This memorandum describes the development process for the Maximum Achievable Control Technology (MACT) floor for the coal- and oil-fired electric utility steam generating units under the National Emission Standards for Hazardous Air Pollutants (NESHAP). The memorandum presents the methodology used to develop the MACT floor, the assumptions used for the analysis, the data sources, and the resulting MACT floor determination for new and existing sources.

MEMORANDUM OUTLINE

1.0 INTRODUCTION

Over the span consisting approximately the last 10 years, EPA along with the Department of Energy (DOE) and industry stakeholders have been researching information and gathering and analyzing data for development of the MACT standard for electric utility steam generating units. The process has culminated in several reports and publications by EPA and others. This memorandum serves to provide an overview of the process as it relates to development of the MACT floor for the standard. The docket for the standard development contains studies, data, reports and memoranda that support and provide basis for the discussion below. The EPA has determined that the MACT standard will only address mercury (Hg) from coal-fired units and nickel (Ni) from oil-fired units. For the sake of simplicity, the term "electric utility steam generating unit," as defined in Clean Air Act (CAA) section 112(a)(8), will be referred to as "unit" (i.e. referring to either coal-fired or oil-fired) in this memorandum. In addition, the acronym "HAP" as used in discussion refers to only Hg and/or Ni as is appropriate for the use of the term in context. For ease of reference, Appendix 10.1 contains a list of acronyms used throughout the memorandum.

2.0 BACKGROUND INFORMATION

2.1 Statutory and Regulatory Requirements

Section 112(a)(8) of the Act defines an "electric utility steam-generating unit" as "any fossil-fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale." A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also considered an electric utility steam-generating unit.

All standards established pursuant to section 112(d) of the Act must reflect the maximum degree of HAP emission reduction achievable by the industry source category. For existing sources, MACT cannot be less stringent than the average emission reduction achieved by the best-performing 12 percent of sources for a category or subcategory with 30 or more sources for which the Administrator has data. The term "average," as it pertains to MACT floor determinations for existing sources and described in section 112(d)(3) of the Act, is not defined in the statute. In a Federal Register notice published on June 6, 1994 (59 FR 29196), the EPA announced its conclusion that Congress intended "average" as used in section 112(d)(3) to mean a measure of mean, median, mode, or some other measure of central tendency. The EPA concluded that it retains substantial discretion within the statutory framework to set MACT floors at appropriate levels, and that it construes the word "average" (as used in section 112(d)(3)) to authorize the EPA to use any reasonable method, in a particular factual context, of determining the central tendency of a data set. For new sources, the Act requires that MACT be based on the degree of emissions reductions achieved in practice by the best-controlled similar source.

These minimum stringency levels are often referred to as the "MACT floor." The MACT floor is based on any combination of measures or techniques that are ascertained to have contributed to the level of emission reductions demonstrated by the best unit(s) (e.g., pollution prevention alternatives, capture and control technologies, operational limitations, or work practices). The MACT standard for the source category would require all new and existing sources in the source category to achieve the corresponding “floor” level of performance on a continuous basis. Because the MACT represents the level of reduction in HAP emissions that is actually demonstrated by the best-controlled source(s) in the subcategory, EPA may not consider cost and other impacts in determining the standard.

The following sections describe the process used by EPA to determine the MACT floor for new and existing units in the coal- and oil-fired electric utility source category.

2.2 Data Sources

Various sources of data were used in the MACT floor analysis for coal-fired and oil-fired electric utility units. For the coal-fired units, EPA's 1999 Electric Utility/Information Collection Effort (EU/ICE) Part II configuration database was used to characterize the number and types of existing boilers, the types of fuels burned, the capacity of the boilers, the types of existing add-on control technologies, and the locations of these facilities. This database includes information on 1,143 units (in 1999). The 1,143 units were located at a total of 461 facilities. The EU/ICE Part II coal analysis database was used to characterize the mercury content, chlorine content, and other fuel constituents from all coal-fired electric utility plants for an entire year (1999). This database contains a minimum of three coal analyses per month per plant, as well as detailed fuel usage data on every operating coal-fired electric utility boiler in 1999. The EPA used the EU/ICE Part III stack emission database, which contained the results of all usable EU/ICE speciated mercury emissions stack test reports. The EU/ICE Part III stack emission database contains data from 80 stack emissions tests at 79 units (one unit was tested twice at different times). The EPA also used data from the U.S. Department of Energy (DOE) Energy Information Administration (EIA) Form EIA-767 (1999) “Steam-Electric Plant Operation and Design Report” to obtain data for use in estimating MACT impacts and costs.

To obtain data for the oil-fired units to characterize the number and types of existing boilers, the types of fuels burned, the capacity of the boilers, the types of existing add-on control technologies, estimating MACT impacts and costs, and the locations of these facilities, the

DOE/EIA Form EIA-767 (2001) "Steam-Electric Plant Operation and Design Report" was used. This analysis of this database includes information on 218 oil-fired units (in 2001). To characterize emissions from oil-fired units, stack test data from the EPRI PISCES emissions testing study were used. All of these databases are available on EPA's Electric Utility Steam Generating Units Section 112 Rule Making Web site (http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html), as well as in EPA legacy docket A-92-55. Other data sources used during the MACT floor analysis were published emission test results and regulatory permit information that pertain to coal- and oil-fired electric utility units and from various state air pollution control agencies.

2.3 Affected Source Definition

An affected source under MACT is defined as the equipment or collection of equipment or practices to which the MACT standard limitations or control technology is applicable. The EPA evaluated the effect of several affected source definitions on development of the standard. The CAA defined the source category to be a electric utility steam generating unit. This definition could include all furnace/boiler combinations at an electric utility plant or could refer to only one boiler furnace configuration. The basic tenet of defining "affected source" for the purposes of standard development is to provide a specific identity to the regulated source of emissions to a degree that is reasonable and practical, while accomplishing the goals of the standard. In particular, the affected source definition should be specific enough to avoid overly burdening the industry by regulating fugitive or incidental emissions at a facility. The EPA determined that the affected source would be either an individual coal- or oil-fired unit or a group of units, particularly where units are commonly controlled. An individual unit consists of the combination of a furnace firing a boiler used to produce steam, which in turn is used for a steam-electric generator that produces electrical energy for sale. This affected source definition is based on information provided to EPA that indicates that the configurations of electric utility units at facilities are diverse and that the intent of the standard can be realized at either the individual or group level of identification of the sources.

The EPA determined that further definition of the affected source was necessary with regard to units that burn multiple types of fuels. The EPA determined that:

- If a unit burns coal (either as a primary fuel or as a secondary fuel), or any combination of coal with any other fuel, the unit is considered to be coal-fired under the standard.

- If a unit burns oil only, or oil in combination with natural gas (except as noted below), the unit is considered to be oil-fired under the standard.
- If a new or existing unit burns natural gas exclusively or natural gas in combination with oil whereas the oil constitutes less than two percent of the unit's annual fuel consumption, the unit is considered to be natural gas-fired and would be exempt from the standard.

2.4 Description of Industry Characteristics

The EPA conducted a thorough analysis of all the data sources mentioned above to gain an understanding of the coal- and oil-fired electric utility industries' process configurations, fuel characteristics, and Hg and Ni emissions. The following section contains an overview of the industry characteristics pertinent to determination of the MACT floor level of performance and development of the MACT floor basis.

2.4.1 Fuel of Coal-fired Units. For the purpose of the development of the MACT standard, coal is defined as all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by American Society for Testing and Materials (ASTM) Designation D388-77, 90, 91, 95, or 98a. The ASTM standard classifies coals by rank, a term which relates to the carbon content of the coal and other related parameters such as volatile-matter content, heating value, and agglomerating properties. The higher heating value (HHV) of coal is measured as the gross calorific value, reported in British thermal units per pound (Btu/lb). The heating value of coal increases with increasing coal rank. The youngest, or lowest rank, coals are termed lignite. Lignites have the lowest heating value of the coals typically used in power plants. Their moisture content can be as high as 30 percent, but their volatile content is also high; consequently, they ignite easily. Next in rank are subbituminous coals, which also have a relatively high moisture content, typically ranging from 15 to 30 percent. Subbituminous coals also are high in volatile matter content and ignite easily. Their heating value is generally in between that of the lignites and the bituminous coals. Bituminous coals are next in rank, with higher heating values and lower moisture and volatile content than the subbituminous and lignite coals. Anthracites are the highest rank coals. The coal-fired electric utility industry combusts the following coal ranks, presented in decreasing HHV order: anthracite, bituminous, subbituminous, lignite, and coal refuse (i.e., anthracite coal refuse [culm], bituminous coal refuse [gob], and subbituminous coal refuse). Because of the difficulty in obtaining and igniting anthracite, only a single electric utility boiler in the United States currently (1999) burns anthracite as its only fuel. Because bituminous coal is the most similar coal to anthracite coal based on coal physical characteristics (ash content, sulfur content, HHV), anthracite coal is considered to be equivalent to bituminous coal for the purposes of the MACT development process and, thus, the anthracite-fired unit is considered a bituminous-fired unit. Although there is overlap in some of the ASTM classification properties, the ASTM method of classifying coals by rank generally is successful in identifying some common core characteristics that have implications for power plant design and operation.

The rank of coal to be burned has a significant impact on overall plant design. The goal of the plant designer is to arrange boiler components (furnace, superheater, reheater, boiler bank, economizer, and air heater) to provide the rated steam flow, maximize thermal efficiency, and minimize cost. Engineering calculations are used to determine the optimum positioning and sizing of these components, which cool the flue gas and generate the superheated steam. The accuracy of the parameters specified by the owner/operators is critical to designing and building an optimal plant. The rank of coal burned also has significant impact on the design and operation of the emission control equipment (e.g., ash resistivity impact on ESP performance).

One of the most important factors in modern electric utility boiler design involves the range of coal ranks to be fired, which determines the design specifications and overall arrangement of boiler components. Coal rank is so important that plant designers and manufacturers require a complete list of all coal ranks presently available or planned for future use, along with their complete chemical and ash analyses, so that the engineers can properly design and specify plant equipment. The various coal characteristics (e.g., how hard the coal is to pulverize, how high its ash content, the chemical content of the coal, how big the boiler has to be to adequately utilize the heat content, etc.), all impact on boiler design from the pulverizer through the boiler to the final steam tubes. For a boiler to operate efficiently, it is critical to recognize the differences in coals and make the necessary modifications in boiler components during design to provide optimum conditions for efficient combustion. As would be expected, coal-fired units are designed and constructed with different process configurations partially because of the constraints placed on the initial design of the unit by the fuel to be used.

Accordingly, these site-specific constraints dictate the process equipment selected, the component order, the materials of construction, and the operating conditions.

The EPA found that a portion of the coal-fired units burn more than one rank of coal. Approximately 23 percent of coal-fired electric utility steam generating units either (1) co-fire two or more ranks of coal (with or without other fuels) in the same boiler, or (2) fire two or more ranks of coal (with or without other fuels) in the same boiler at different times.[2] This coal "blending" is done generally for one of three reasons: to achieve sulfur dioxide (SO_2) emission compliance with CAA Title IV provisions, to prevent excessive slagging by improving the heat content of a lower grade coal, or for economic reasons (i.e., coal rank price and availability). However, these blended coals, although of different rank, have similar properties. That is, because of the overlap in various characteristics in the ASTM definitions of coal rank, certain bituminous and subbituminous coals (for example) exhibit similar handling and combustion properties. Plant designers and operators have learned to accommodate these blends in certain circumstances without significant impact on plant operation or control. The majority of coal-fired units in the United States firing multiple coals fire bituminous and subbituminous coals, either through direct blending or through independently combusting each coal at some period during the year. In the United States, the number of units that burn a majority of bituminous coal in their mix (9 percent of all units in the United States) is nearly double the number of units that burn a majority of subbituminous coal (5 percent of all units in the United States). Also, some units co-fire subbituminous and lignite coals.

The flue gases resulting from the combustion of these different coal ranks can exhibit different Hg emissions characteristics. These Hg emissions characteristics consist of varying percentages of the three relevant forms (or species) of Hg (particulate-bound, oxidized [ionic], and elemental) that make up the total Hg in the flue gas.

Analysis of available source test data and Hg in coal data shows that combustion of bituminous coal results in Hg emissions that are composed of relatively more oxidized Hg compared to the other coal ranks. Combustion of bituminous coal produces the most particulate-bound Hg of any of the three major coal ranks combusted. Combustion of subbituminous coal results in emissions that are composed of relatively more Hg^0 (compared to bituminous coal), with little particulate-bound Hg (less than half that of bituminous coal emissions). Combustion of lignite coal also results in emissions that are composed of relatively more Hg^0 (compared to bituminous coal) with little particulate-bound Hg (also less than half that of bituminous coal emissions). Available data indicate that emissions from the combustion of coal refuse tend to speciate almost entirely to particulate-bound Hg (greater than 99 percent for both units tested in the EU/ICE). With few exceptions, particulate-bound Hg can be removed with PM controls, oxidized Hg can be removed with wet SO_2 controls (flue gas desulfurization [FGD] scrubbers), but Hg^0 usually shows little to no removal with any existing conventional type of air pollution control device (APCD) such as ESP or FF units used on utility boilers. Appendix 10.3 of this document provides the data and results of an analysis of coal-fired units with regard to speciation in Hg across coal ranks.

Other types of fuel are blended with coal for a variety of unit-specific needs. The two most common "supplementary fuels" in the coal-fired industry are petroleum coke and tire-derived fuel (TDF). These supplementary fuels are generally blended with a much larger percentage of coal before combustion. If a unit were to burn one, or a combination of these supplementary fuels exclusively, it would not be subject to the coal- and oil-fired electric utility NESHAP. To our knowledge, oil is used only during start-up of coal-fired units and is not a "supplementary" fuel for these units.

2.4.2 Boiler Firing Configurations Used in the Coal-fired Electric Utility Industry. There are five basic types of coal combustion processes used in the coal-fired electric utility industry. These are conventional-fired boilers, stoker-fired boilers, cyclone-fired boilers, IGCC units, and fluidized bed combustors (FBC).

Conventional boilers, also known as pulverized coal (PC) boilers, have a number of firing configurations based on their burner placement. The basic characteristic that all conventional boilers have in common is that they inject PC and primary air through a burner where ignition of the PC occurs, which in turn creates an individual flame. Conventional boilers fire through many such burners mounted in the furnace walls.

In stoker-fired boilers, fuel is deposited on a moving or stationary grate or spread mechanically or pneumatically from points usually 10 to 20 feet above the grate. The process utilizes both the combustion of fine coal powder in air and the combustion of larger particles that fall and burn in the fuel bed on the grate.

Cyclone-fired boilers use several water-cooled horizontal burners that produce high-temperature flames that circulate in a cyclonic pattern. The burner design and placement cause the coal ash to become a molten slag that is collected below the furnace.

Fluidized bed combustors combust coal in a bed of inert material (e.g., sand, silica, alumina, or ash) and/or a sorbent such as limestone that is suspended through the action of primary combustion air distributed below the combustor floor. "Fluidized" refers to the state of the bed of material (coal and inert material [or sorbent]) as gas passes through the bed. As the gas flow rate is increased, the force on the fuel particles becomes just sufficient to cause buoyancy. The gas cushion between the solids allows the particles to move freely, giving the bed a liquid-like (or fluidized) characteristic.

Integrated-coal gasification combined cycle units are specialized units in which coal is first converted into synthetic coal gas. In this conversion process, the carbon in the coal reacts with water to produce hydrogen gas and carbon monoxide (CO). The synthetic coal gas (syngas) is then combusted in a combustion turbine which drives an electric generator. Hot gases from the combustion turbine then pass through a waste heat boiler to produce steam. This steam is fed to a steam turbine connected to a second electric generator.

2.4.3 APCD Used to Control Coal-fired Emissions. Coal-fired electric utility units are controlled by a varied group of APCD depending on individual fuel characteristics and design considerations. The following discussion describes those possible configurations.

a. PM Controls. The two major types of PM APCD used in the coal- and oil-fired electric utility industry are ESP and FF. Particulate scrubbers are used on a limited number (25) of coal-fired units in the United States and mechanical APCD (multiclones) are used on 41 of 218 oil-fired units and only one coal-fired unit. [2]

Electrostatic precipitators are the most frequently used PM control devices on coal- and oil-fired electric utility units. They operate by imparting an electrical charge to incoming particles, then attracting the particles to oppositely charged plates for collection. The collected particles are periodically dislodged in sheets or agglomerates by rapping the plates. Particle removal in an ESP depends largely on the electrical resistivity of the particles being collected. There are two basic configurations of ESP, cold-side and hot-side. Cold-side ESP are located after the unit's air preheater while hot-side ESP are located before the unit's air preheater.

Fabric filters are inherently efficient and are effective when high-efficiency PM collection is required. Fabric filters collect PM by placing a fabric barrier in the flue gas path. Gas passes freely through the fabric, but particles are trapped and retained for periodic removal.

Particulate scrubbers operate by shattering streams of water into small droplets that collide with and trap PM contained in the flue gas or by forcing the flue gas into intimate contact with water films. The particle-laden droplets or water films coalesce and are collected in a sump at the bottom of the scrubber.

Mechanical collectors are generally in the form of groups of cylinders with conical bottoms (multicyclones). Particles in the entering gas stream are hurled to the outside of the cylinder by centrifugal force and are discharged at the bottom of the cone.

b. SO_2 Controls. The two major types of SO_2 APCD used in the coal-fired electric utility industry are known as wet scrubbers and dry scrubbers.

In a wet scrubber, flue gas containing SO_2 is brought into contact with a alkali sorbent-water slurry. The most often used sorbent is limestone. The SO_2 is absorbed into the slurry and reacts with alkali sorbent to form an insoluble sludge. The sludge is usually disposed of in a pond specifically constructed for the purpose.

In a dry scrubber (known as an spray dryer adsorber [SDA]), flue gas at the air preheater outlet is contacted with fine spray droplets of hydrated lime slurry in a spray dryer vessel. The SO_2 is absorbed in the slurry and reacts with the hydrated lime reagent to form solid calcium sulfite and calcium sulfate, as in a wet lime scrubber. The water is evaporated by the heat of the flue gas. The dried solids are entrained in the flue gas, along with fly ash, and are collected in a PM collection device (FF or ESP).

2.4.4 Fuel for Oil-fired Units. The EPA analyzed the data available on the fuel, process, emission profiles, and APCD for oil-fired units at existing affected sources. The ASTM classifies oils by "grade," a term which relates to the amount of refinement that the oil undergoes. The level of refinement directly affects the metallic HAP and carbon content of the oil and other related parameters such as sulfur content, heating value, and specific gravity. The heating value of oil is measured as the gross calorific value, reported in British thermal units per gallon (Btu/gal), and increases with increasing oil grade. The most refined oil used by the oil-fired electric utility industry is amber in color and known as distillate oil (also known as medium domestic fuel oil). The least refined oil used by the oil-fired electric utility industry is black in color and known as residual oil (also known as Bunker C oil). By comparison, distillate oil is lower in metallic HAP, sulfur, ash content, and heating value but higher in carbon content than residual oil. Only a handful of boilers (8 of 218) fire distillate fuel oil exclusively. However, 28 out of 218 boilers fire distillate oil and residual oil in the same boiler (either simultaneously or at separate times). To EPA's knowledge, number 1, 3, 4, and 5 fuel oils are not used currently in the oil-fired electric utility industry.[4]

The type of oil to be burned has little impact on overall plant design. The goal of the plant designer is to make sure the plant can handle the different viscosities of oil (and natural gas if applicable) that the boiler is likely to combust. For example, because of its viscosity, residual oil must be heated to make it flow (i.e., heated storage tanks and heated fuel supply lines).

An oil-fired electric utility boiler combusts oil exclusively, or combusts oil at certain times of the year and natural gas at other times (not simultaneously). The choice of when to combust oil exclusively or the blend of oil and natural gas at a single boiler is usually based on economics or fuel availability (including seasonal availability). Additionally, the blended unit could also potentially burn a blend of distillate and residual oil.

2.4.5 Boiler Firing Configuration Used in the Oil–fired Electric Utility Industry. There is only one basic type of oil combustion process used in the oil-fired electric utility industry, known as a conventional-fired boiler. Conventional-fired boilers have a number of firing configurations based on their burner placement. The basic characteristic that all conventional-fired boilers have in common is that they inject oil and primary air through a burner where ignition of the oil occurs, which in turn creates an individual flame. Conventional-fired boilers fire through many such burners mounted in the furnace walls.

2.4.6 APCD Used to Control Oil–fired Emissions. Only 79 of the 218 oil-fired units mentioned above have any APCD controlling their emissions. Uncontrolled units represented the largest portion of the oil-fired units (64 percent). Electrostatic precipitators were used on 38 units, which constitute 17 percent of the oil-fired units in the oil-fired industry. Mechanical controls (cyclones and multiclones) were used on 41 units, which constitute 19 percent of the oil-fired units. Three units have both mechanical controls and ESP. These three units with both controls were included in the ESP equipped units count above.[4]

3.0 SUBCATEGORIZATION ANALYSIS

The definition of affected source for this source category includes a wide range of regulated units with varying process configurations and emission profile characteristics. In order to develop the MACT standard, EPA must consider the variation in the sources within the category to determine if any variations between the sources would be significant enough to warrant subcategorization. The subcategorization of sources within the source category is necessary when sources exhibit differences in operation, design, size, or raw materials used (etc.) that would limit the feasibility of developing standards that equitably address the entire population of sources. The EPA must provide a standard that is based on emissions reductions that can be achieved by all sources with technology demonstrated to be available and effective for those sources. Therefore, it was necessary for EPA to determine the appropriate level of subcategorization for the coal- and oil-fired units. The criteria used by EPA in evaluating differences in sources for this standard included the fuel used, the process design or operation of the unit, variations in emissions profiles from the source, and differences in application of control technology (APCD or work practices).

3.1 Coal and Oil Subcategories

For the coal- and oil-fired electric utility steam generating unit source category, the affected sources exhibited obvious and significant variations with regard to these criteria. The most prominent dissimilarity was that between coal- and oil-fired units. Coal- and oil-fired units have vastly different emission characteristics due to their fuel sources. The electric utility industry generally uses coal-fired units as base-loaded units (i.e., the units are designed to run continuously except for maintenance intervals). Oil-fired units are generally used as “peaking” units (i.e., the units are operated when extra electrical power is needed). Coal combustion produces higher emission levels of metals, halogenated inorganic compounds, and organic compounds than a comparably sized oil-fired unit, with the exception of emission of Ni compounds. For these reasons, EPA divided the affected sources into the initial subcategories of coal- and oil-fired units. Additional evaluation of the data were then conducted to ascertain if further subcategorization within coal-fired or within oil-fired units was warranted.

3.2 Subcategorization within Coal-fired Units

After examining a number of possible subcategorization options, EPA identified three basic ways to subcategorize coal-fired electric utility steam generating units.

- A no subcategorization scheme which would treat all coal ranks as one, with the MACT floor developed using all of the coal-fired unit data.
- Subcategorization by coal rank which would address the differences in the characteristics of the Hg emissions (i.e., speciation of Hg), the resulting ability to control Hg, and the various design and control constraints resulting from the various coal ranks.
- Subcategorization by process type which would address potential emissions differences produced by process variations, which in turn lead to corresponding differences in the nature of emissions and the technical feasibility of applying emission control techniques.

To determine the appropriate subcategorization approach, EPA evaluated fuel, process, and control technology to determine which aspect determined the better performance by the top units and found that the data did not identify any common attribute that could be credited with the demonstrated better performance. The EPA found that each of the best-performing units had a combination of factors that was the basis for the better performance. The factors that were identified to contribute to the better performance were more closely fuel-dependent than either APCD or process-dependent. The dependency on fuel as a controlling factor was particularly prominent with regard to Hg emissions. A top-performing unit may have lower Hg emissions because a combination of events took place (e.g., the coal may have been of a lower Hg content, and/or the Hg may have been primarily speciated to a particulate form, and/or the unit may have been controlled for PM using a FF). In this case, the lower level of the Hg in the coal and its speciation form were the controlling factors in the better performance. Conversely, if the Hg level was higher in the coal and/or the Hg speciated to another form, the demonstrated performance would not be as good even if controlled by the same control device. The data also indicated that both factors, the Hg in the coal and the speciated form of the Hg, are dependent on coal rank (or even coal seam within a rank).

Based on this information, EPA then analyzed the available data to determine which coal ranks were burned, and why, to ascertain if changing coal rank would be a conceivable control strategy. The EPA found that the characteristics of the coal rank to be burned were the driving factors in how a coal-fired unit was designed. Further, the choice of coal ranks to be burned for a given unit is based on economic issues, including availability of the coal within the region or locale. A number of coal-fired units, including all known lignite-fired units, are “mine mouth” (or near mine-mouth) operations (i.e., the unit is constructed on or near the coal mine itself, with coal transport often being done by conveyor directly from the mine) and many do not have the infrastructure in place (e.g., interstate rail lines) to import other ranks of coal in quantity sufficient to replace all lignite coal combusted. Additionally, many plants have long-term contract obligations to burn low-sulfur-content coal to achieve compliance with SO_2 standards. This coal is delivered to the plants by large unit-trains from very long distances. Thus, a standard based on “no subcategorization” could be unachievable for such units at such plants with fixed fuel delivery (by physical location or by contractual agreement) requirements. The EPA also found that substitution of coal rank, in most cases, would require significant modification or retooling of a unit, which would indicate a valid difference in the design/operation of the units. For these reasons, EPA decided that subcategorization of coal-fired units based on coal rank (fuel type) was warranted.

Although conventional-, stoker-, and cyclone-fired boilers use different firing techniques, the Hg emissions characteristics of these boilers are similar (given that common ranks of coal are fired) and, therefore, the units can be grouped together. Although these units fire a variety of coal ranks, they have, to date, only combusted coal refuse in lesser amounts as a secondary fuel source.

Based on their unique firing designs, FBC units employ a fundamentally different process for combusting coal from that employed by conventional-, stoker-, or cyclone-fired boilers. Fluidized-bed combustors are capable of combusting many coal ranks, including coal refuse. For these reasons, FBC units can be considered a distinct type of boiler. However, the Hg emissions test data results for FBC units were not substantially different from those at similarly fueled conventionally fired units with similar emission levels, either in mass of emissions or in emissions characteristics. Therefore, EPA does not believe subcategorization of FBC units is necessary.

Integrated gasification combined cycle units combust a synthetic coal gas. No coal is directly combusted in the unit during operation (although a coal-derived fuel is fired), and thus, IGCC units are a distinct class or type of boiler.

3.3 Subcategorization within Oil-fired Units

The EPA analyzed the data available on the fuel, process, emission profiles, and APCD for oil-fired units at existing affected sources. The data available to EPA on oil-fired units indicated that there is very little variation in the process or control technologies used in the industry.

3.4 Subcategorization Options Considered

The EPA had determined that subcategorizing coal-fired units into five subcategories; bituminous coal, subbituminous coal, lignite coal, coal refuse, and IGCC is the most obvious subcategorization scheme. Another possible option is to subcategorize coal-fired units into four subcategories (bituminous and subbituminous coals, lignite coal, coal refuse, and IGCC). This second option is claimed by some industry sources to allow greater fuel choice flexibility. As mentioned previously, approximately 23 percent of the coal-fired units in 1999 fired a blend of coal ranks or coals and other fuels.[2] The majority of blended coal-fired units in the United States combust a blended coal composed of bituminous and subbituminous coal, either through direct blending or through independently combusting each coal at some period during the year. A standard that would subcategorize bituminous and subbituminous together would allow easier emissions permitting and flexibility because most blended coal-fired units do not keep the ratio of the coals blended constant.

3.5 Subcategorization of Existing Units

Based on the above information, EPA believes the coal-fired units at existing affected sources should be subcategorized into five subcategories based on a combination of coal rank and process type: bituminous (including anthracite), subbituminous, lignite, coal refuse (which includes anthracite, bituminous, and subbituminous coal refuse), and IGCC (coal syngas). Because few units fire anthracite coal, EPA chose to combine it with bituminous coal for the purposes of this standard development. Because petroleum coke and TDF do not meet the definition of a fossil fuel, EPA does not believe that they should be given their own subcategories.

As mentioned above, the data available to EPA on oil-fired units indicated that there is very little variation in the process or control technologies used in the industry. Also, because units burning greater than or equal to 98 percent natural gas (based on the annual Btus contributed by all fuels burned) would not be subject to the standard and units burning distillate oil, exclusively, would be exempt from compliance requirements of the standard, EPA does not think that natural gas and distillate oil should be given their own subcategories. Therefore, EPA found no criteria that would warrant further subcategorization within existing oil-fired units.

3.6 Subcategorization of New Units

With regard to new sources, EPA has no data that indicate that the rationale for subcategorization for existing sources would not be applicable to new units. New units constructed on the same site as existing units could still be restricted, at least in concept, to the same physical constraints (e.g., coal handling and processing, access to interstate rail lines) as are the co-located existing units. Further, the variability of Hg content within a coal rank and within specific coal seams would preclude the ability to find a consistent source of low-Hg coal. For these reasons, EPA believes that the subcategorization scheme for new coal- and oil-fired units should be the same as for the existing units.

4.0 EVALUATION OF MACT FLOOR PERFORMANCE FOR EXISTING UNITS

Once the sources were subcategorized, EPA then evaluated each subcategory to determine the best performing units and further, the attributes by which the best performing units demonstrate the better performance. The following sections summarize the evaluation to determine the MACT floor units and of the attributes which could contribute to better performance.

4.1 Pollution Prevention Alternatives

Pursuant to current EPA policy, the development of all MACT standards must consider, as a potential MACT control strategy, any pollution prevention techniques that could reduce or eliminate the pollutants of concern from being produced by the process. During development of the electric utility standard and other combustion-related rules, EPA considered several pollution prevention techniques as alternatives to application of add-on pollution control technology. Each of the measures considered are “pre-combustion” techniques that would address formation of HAP prior to the fuel being combusted in the furnace. The measures evaluated include fuel substitution or treatment, combustion process changes, and work practices, all of which could potentially increase combustion efficiency and decrease production of HAP from the combustion process.

4.1.1 Fuel Substitution or Treatment. The fossil fuels used in the electric utility industry consist of primary fossil fuels such as coal, oil, and natural gas. In addition there are several supplementary fuels (as mentioned earlier) used to enhance the combustion process. The Administrator has previously determined that HAP emissions from the burning of natural gas are not significant and, therefore, has determined that natural gas-fired units are not included in this standard development. It would follow that since the HAP emissions from natural gas are low, it would be a desirable alternative to substitute natural gas for the coal and oil currently burned in the industry. If a unit could not switch to natural gas, then perhaps it would be possible to decrease HAP produced by burning a "better" type of coal or oil (based on HAP content in the fuel to start with or the behavior of the fuel during the combustion process). The EPA first considered the feasibility of fuel substitution from several perspectives: (1) switching to natural gas; (2) switching to other fuels in the same subcategory (e.g., a "lower" Hg or other HAP content bituminous coal, or distillate oil instead of residual oil); or (3) switching to fuels used in another subcategory (e.g., firing bituminous coal instead of lignite coal). The EPA considered several aspects of fuel switching in evaluating these alternatives. These aspects included whether switching fuels would actually achieve lower HAP emissions, whether fuel switching could be technically achieved considering the process design characteristics of the units, and the availability of various types of fuel.

For both coal-fired and oil-fired units, the first alternative considered was switching to natural gas. Based on all data available to EPA, and as was published in the Utility RTC, HAP emissions from the burning of natural gas are significantly lower than that of either coal or oil as a fuel. Although some coal-fired units utilize natural gas as a start-up fuel, the design and configuration of the furnace unit would not support the burning of natural gas easily. The primary burner configuration of coal fired units is designed to accommodate the large coal loads common for production units. The burner configuration for the start-up warming using natural gas would only accommodate small fuel loads and is not sufficient for production. Some oil-fired units burn natural gas instead of oil on a seasonal basis, a practice which is primarily economically driven and based on the availability and price of oil. In most cases, the design characteristics of the primary burner configuration of the oil-fired units would allow use of natural gas as a primary fuel The major limiting factor with regard to mandating use of natural gas instead of coal or oil is the availability of natural gas for a given unit. Natural gas pipelines are not available in all regions of the United States. In addition, even where pipelines provide access to natural gas, supplies of natural gas may not be available in adequate quantities for utilities to maintain capacity production when necessary. For example, it is common practice in large metropolitan areas during winter months (or periods of peak demand) to prioritize natural gas usage for residential areas before industrial areas. Requiring an EPA-regulated utility unit to switch to natural gas would place an even greater strain on natural gas resources, and, in some circumstances, the change would interfere with ability to run at full capacity. For these reasons, EPA decided that mandating switching to natural gas is not an appropriate alternative for a MACT control strategy for existing coal- or oil-fired units.

Another alternative in fuel substitution would involve the use of a better (e.g., lower-Hg-containing) seam of coal within a subcategory, or switching between subcategories for coal-fired units, or switching from one type of oil to another (i.e., residual oil to distillate oil). The issue related to switching between coals involves the disparity of HAP constituents in different seams of coal and the disparity of HAP emissions from different seams of coal. The data indicate that, although one seam may have less Hg than another, it may be higher in another HAP. Further, as discussed previously, the amount of Hg in coal is not the only factor influencing its control. The speciation of Hg in the flue gas is another characteristic that differs between seams of coal. The data show that although a coal may have a lower Hg loading in the coal, the Hg emissions may be more difficult to control if that seam of coal tends to speciate Hg to an elemental form. The EPA reviewed coal data from the EU/ICE coal content and found a wide range of HAP constituents in the coal; however, the data does not support identification of the "best" seam, or rank, of coal on which to base such a requirement. Further, the HAP constituent loading of different coal ranks and/or seams of coal tends to be similar for coals from the same region, although that was not universal. Therefore, even if a "better/best" seam or rank of coal could be identified, changing to a specific or different rank or seam of coal would essentially determine the area or even mine from which the coal could be produced. The fuel substitution issue then becomes dependent on the regional differences in coal characteristics and the subsequent feasibility of placing a burden on units that are located further from the "better/best" seams, and even more importantly, the extent of the coal deposits and the ongoing availability of that particular coal. The EPA believes that the intent of the Act was to develop standards that were consistent across the industry and avoid actions that create regional disparities between units or place an unreasonable burden on any local natural resource.

Another perceived use of alternate ranks or seams of coal could be to use clean coal. The term "clean coal" generally refers to a fuel that is lower in sulfur content. Data gathered by EPA indicate that within specific coal ranks, the HAP content can vary significantly and that lower sulfur content does not necessarily mean lower HAP content. In some cases, it was found that low-sulfur-coal may actually result in an increase in emissions of some HAP, including Hg. In addition, EPA has determined (as stated earlier) that the existing utility units were designed based on the availability of certain coal ranks and found that, in some instances, the units were actually built co-located with a particular coal source. (i.e., many lignite-fired units).

The EPA has determined that coal ranking and subsequent system design characteristics are issues that are formidable enough to warrant subcategorization within the coal-fired units. A unit may require extensive changes to the fuel handling and feeding system (e.g., a stoker using bituminous coal as fuel would need to be redesigned [i.e., retooled]) in order to burn a different rank of coal. Additionally, existing burners and combustion chamber designs are generally not capable of handling different fuel types and generally cannot accommodate increases or decreases in the fuel volume and shape. Design changes to allow different fuel use may, in some cases, reduce the capacity and efficiency of the unit. Reduced efficiency may result in less complete combustion and, thus, an increase in organic HAP emissions.

4.1.2 Process changes. Process changes would be considered a pollution prevention alternative when a change to the process that emits the HAP could be made to reduce or eliminate the HAP emissions. Process changes for the electric utility process might include changes to furnace or boiler design; changes in fuel storage; changes to handling and feeding systems; or changes to burner or component configuration. The HAP of concern for this standard include Hg and from coal-fired units and Ni from oil-fired units. The EPA found that both Hg and Ni emissions are primarily a result of the combustion process itself and that the loading and type of HAP emissions are more dependent upon the composition of the fuel and, to a lesser extent, the combustion process. Consequently, process changes (i.e., changes to unit design, configuration, or operation) would have very little effect in reducing these type HAP emissions. Further, EPA did not identify any process changes that would have an effect on reducing Hg or Ni emissions from the combustion process. Therefore, EPA determined that process changes would not be an appropriate criteria for identifying the MACT floor level of control for existing or new coal- or oil-fired units.

4.1.3 Work Practices. Work practices for combustion sources are those practices that would promote and support efficient combustion and are also known as "Good Combustion Practices" (GCP) in the industry. Good combustion practices are dependent on the specific type of equipment utilized and fuel input to the combustion device. Operations-based GCP include documented operating procedures, operating logs/record keeping, operator training, documented maintenance, inspection and overhaul procedures. Good combustion practices with regard to fuels include fuel quality (analysis), and fuel handling. The EPA's research was unable to identify any uniform requirements or set of work practices that would meaningfully reflect the use of GCP or that could be meaningfully implemented across any subcategory of units, particularly with regard to Hg or Ni emissions.

In general, electric utility units are designed for efficient combustion. Facilities have an economic incentive to ensure that fuel is not wasted and that the combustion device operates properly and is appropriately maintained. Therefore, EPA decided that establishing combustion practice requirements as a part of the MACT floor for existing or new coal- or oil-fired units would not be necessary or useful.

4.2 Regulatory Approach

The EPA's policy for MACT standard development is to allow as much flexibility as possible for the regulated industry to develop and implement new and more effective control technologies. Therefore, EPA strategy remains focused on developing standards that provide a target for achievement rather than technology-based requirements, particularly where existing technologies are not proven as effective in addressing the HAP of concern. Accordingly, EPA decided to address MACT development for Hg from coal-fired units and Ni from oil-fired units using an emission limitation-based approach, as opposed to a control-equipment-based approach. The selection of emission limitations as the format for the standard provides flexibility for the regulated community in that a regulated source may choose any control technology or technique to meet the emission limit that suits the unit or units, rather than requiring each unit to use a prescribed method that may not be appropriate or most cost-effective. This flexibility is particularly relevant for coal-fired electric utility steam generating units due to the potential for widely varying emission profiles and the need for owners/operators to be able to employ control devices that are best suited for their particular emission characteristics.

In order to develop an emission limitation for Hg and Ni that accurately reflects the MACT floor level of performance, EPA evaluated the top performing units based on the stack test data and the control technologies employed by the best performers. The EPA first examined the population database of existing sources and divided the units according to the subcategorization scheme described above; first by coal- and oil-fired, then by the five subcategories of coal-fired units. The EPA then examined the stack test data to determine the individual numerical mean of the stack test results and ranked the units from lowest to highest within each subcategory for each regulated HAP (or surrogate). The EPA then determined which units represented the top 12 percent (or equivalent) of the units for which EPA had test data for each subcategory (based on the lowest stack test mean emission rate). The EPA then evaluated those units to determine what criteria could be credited with the better performance and how that could be translated into the MACT floor level of performance. The sections below describe the evaluation of the better performing units for purposes of deciding how the MACT standard should be developed for Hg from coal-fired units and Ni from oil-fired units.

4.3 Control Technology Performance Analysis

The MACT floor determination must be based on demonstrated performance. The first test for EPA to determine a basis for performance is to determine what control technology is commonly used and is effective in controlling the pollutants of concern. In this case, EPA used existing industry information and test data from EU/ICE as well as results and findings of the Utility RTC to evaluate control technology performance as it relates to Hg and Ni and its potential use as MACT floor level of control.

4.3.1 Control equipment performance with regard to Hg. The EPA initiated the evaluation of the units within each subcategory by ranking them from lowest to highest based on emission rates representing the outlet Hg concentration of the stack tests. The better performing units were controlled by either FF or ESP units, with FF being the predominant technology used in the top performing units. Evaluation of the test data also indicated that FF and ESP technology were also used at some of the worst performing units. The effectiveness of the FF, ESP, and other technology used was inconsistent, even within a subcategory of coal. Further, the evaluation of the test report data indicated that no specific control technology or combination of technologies could be credited with the better performance; however, the evaluation indicated that FF technology did provide a degree of removal of Hg and that ESP units also provided a degree of removal, although to a less consistent and lower degree than FF-equipped units. Over the last several years, EPA and other organizations have conducted a significant amount of research with regard to control of Hg from combustion processes. The outcome of the research indicates that FF and ESP control technologies are effective for the control of Hg in flue gas streams; however, the effectiveness is more dependent on the Hg loading and Hg speciation in the flue gas than on the control technology applied. The demonstrated performance of the units further supported this conclusion. The information available indicated that since FF and ESP technologies were designed for particulate control, Hg presented in particulate-bound form was readily addressed by both technologies.

This phenomenon was further evaluated using the entire database of coal-fired units to determine if the variations in the control device performances could be correlated to the speciated form of the mercury presented to the APCD. This evaluation encompassed an evaluation of existing coal-fired units from EU/ICE data that provided Hg speciation data, Hg in coal data, and pre- and post-last-control unit emissions test data. The data indicated that where Hg was presented to the control device in particulate-bound form, both control devices provided a degree of control, with FF generally performing better than ESP. Where Hg was presented to the control device in an elemental form, the performance of the various control devices was highly variable. Test data indicate that both the type and the proportion of speciated Hg presented to an APCD are not consistent across units; however, as stated above, the data do indicate that PM controls are reasonably effective where particulate-bound Hg is present. The variation of the proportions of speciated Hg within the flue gas between units provided further explanation for the observed removal characteristics for different units using the same control technology. Using the EU/ICE coal data, EPA analyzed the Hg speciation of the different coal ranks and found that certain coal ranks tend to speciate to a predominantly similar proportion of speciated forms of Hg, thus further supporting the rationale for the subcategorization of coal-fired units by coal rank.

The EPA determined that although variable, FF and ESP control technologies were reasonable and viable technologies on which to base the MACT floor level of control. The EPA then evaluated performance of the various FF- and ESP-equipped units to determine what criteria would most effectively reflect the performance. The EPA considered using the percent removal efficiency of the control device, the percent reduction of Hg from coal to emissions, and outlet concentration as viable criteria to demonstrate performance of the technology.

The EPA first evaluated percent removal efficiency as the performance criteria on which to base the floor performance; however, the use of the criteria proved problematic. The EU/ICE Hg data were based on stack test data developed by testing before and after the last control device at each utility unit tested. The emissions were measured in mg of Hg per volume of test solution used in the Ontario-Hydro method. Using the duct or stack flue-gas flow volume and the heat input to the unit being tested, the measured quantity of Hg was converted and reported in units of lb/TBtu. In reviewing the data, EPA found that the inlet measurement showed deficiencies due to the flow rate and short duct runs available for testing before the control device and that these values were suspect as reliable representations of actual inlet concentrations. The EPA determined that without reliable inlet concentration data, calculation of percent removal efficiency based on the data would provide potentially inaccurate removal values. As a result, EPA decided that percent removal efficiency would not be an appropriate criteria for MACT floor development due to insufficient data being available to accurately determine the values. The EPA did determine, however, that the outlet concentration data that were derived from the stack tests were reliable based on the method used and the fact that only one measurement was needed for the determination of the value.

The next approach EPA evaluated was determining the percent reduction of Hg demonstrated by the best performing units and using that value as the MACT floor performance level. The percent reduction value would represent the amount of Hg reduction that the unit accomplished based on the Hg in the coal to the stack outlet concentration. This approach would also incorporate EPA’s desire to promote, and give credit for, coal preparation that removes Hg before firing (i.e., coal washing). In order to use the percent reduction value as the criteria for performance, the operator would be required to track Hg concentrations in the coal from receipt to the stack. Tracking and recordkeeping of Hg concentrations in coal is not currently conducted in the industry. Therefore, the issue presented a logistical concern as to what would be involved and how a such tracking method could be uniformly and equitably regulated by the rule. Therefore, EPA determined that the tracking of Hg in the coal would be unworkable from the regulatory perspective. Further, EPA concluded that without the ability to give credit for Hg removal prior to firing, the percent reduction criteria would not be a desirable criteria on which to base MACT floor performance.

4.3.2 Control equipment performance with regard to Ni. The EPA examined available test data and found that units equipped with ESP units (for PM control) can effectively reduce Ni. The controls currently in use on electric utility oil-fired units to address PM were installed as a result of requirements to address criteria pollutants under other regulations. The data available to EPA indicate that the Ni is present in flue gas streams in varying concentrations, yet mostly in particulate form. The Utility RTC emissions test data support the conclusion that the same control techniques used to control the fly-ash PM will also indiscriminately control Ni and that the effective removal of PM indicates removal of Ni, for a given control device. Therefore, EPA believes that ESP technology represents the MACT floor for Ni. The EPA has determined that the emission limitation for the oil-fired units should reflect the performance that would be expected over time for a well designed and operated ESP unit PM removal technology. The EPA determined that the better performing units within the database were all equipped with ESP units.

4.3.3 Conclusion. As a result of these evaluations, EPA determined that the most credible data element available that quantified the better performance of the top units would be the outlet concentration as provided in the stack test reports (translated into emission rate). In order to use these data elements as the criteria representing the MACT floor level of control or performance, EPA would need to develop an emission limitation for Hg and Ni based on the stack test result values that would be representative of the average performance of the top 12 percent of the units in each subcategory on an ongoing basis.

5.0 EMISSION LIMITATION DETERMINATION FOR EXISTING UNITS

The EPA evaluated several format options for the limits including the formats used for previous combustion rules, formats representing standard practice within the industry with regard to data tracked and reported, and formats suggested by industry and stakeholder groups.

The options evaluated included emission limitation, percent reduction, and outlet concentration formats. The emission limitation option can be described as a not-to-exceed numerical value expressed as a rate. The emission limitation would be derived by determining the mass of HAP emissions that represents the average HAP reduction demonstrated by the top performing units. The rate component of the limitation would include some input- or output-based parameter that is representative of the industry. The percent reduction format is a value presented in the form of a percentage that represents either the percent reduction of HAP demonstrated by the top-performing units based on the efficiency of the control equipment and/or the use of mass balance calculations where control equipment efficiency is not applicable. Finally, the outlet concentration format presents a numerical value in the form of a concentration (mass/volume) that would be a not-to-exceed value and would be derived in the same manner as the mass component of the emission limitation.

Where an emission limitation is used, EPA must also determine what basis will be used as the rate characteristic. For the electric utility industry, the input-based characteristic would be heat or power input to the unit in order to generate steam. The output-based characteristic would be the amount of heat or power (electricity) generated. Finally, EPA must also consider whether it is appropriate to base the emission limitation on the gross amount of heat/power generated by the system or the net amount of heat/power that is available for sale (less the heat/power used for internal purposes).

For development of the MACT standard, EPA determined that an emission limitation is the appropriate format to be used based on considerations with regard to available data, compliance options, and consistency with other combustion rules. The percent reduction option was not considered appropriate because, as stated earlier, there was no control technology identified that was consistent within any subcategory that could be used as the preferred control technology on which to base a reduction requirement. The EPA also considered using outlet concentration as an alternative format; however, although this format was consistent with other Federal and many State combustion source regulations and allowed easy comparison between requirements, the format did not promote pollution prevention and has become inconsistent with many of the newer regulations.

5.1 Emission Limitation Format

An emission limitation format can be either input-based or output-based (as discussed above). The use of an input-based standard (lb/TBtu) has several advantages: (1) it is consistent with the majority of historical Agency electric utility rulemakings; (2) it would not need to be adjusted for energy requirements for auxiliaries such as emission control equipment; and (3) it does not need to take into account the baseline efficiency of the boiler/furnace.

An output-based standard would have the following advantages: (1) it provides incentive for efficiency upgrades (i.e., an output-based standard would be preferable for promoting energy efficiency in electric utility steam generating facilities); (2) it is consistent with recent Agency rulemakings (e.g., nitrogen oxides [NO_x] new source performance standards [NSPS] revision) and some State actions; and (3) it would not cause an undue compliance burden to the industry.

The EPA has found considerable support for both an input-based and an output-based standard for emission limits for electric utility units. The EPA concludes that both types of format have merit and has decided that both an input-based and an output-based standard would be appropriate for the standard.

With regard to cogeneration units, to comply with an output-based standard, the energy content of the process steam must also be considered in determining the energy output when determining the emission rate. The EPA has determined that existing plant monitoring and energy calculation curves are available and can be easily programmed to determine the steam's equivalent electrical energy component. This component can then can be added to the plant's actual gross electrical output to arrive at the plant's total gross energy output.

The EPA considered two possible output-based formats: (1) mass of HAP emitted per gross boiler steam output (lb HAP/TBtu heat output), and (2) mass of HAP emitted per net energy output (lb HAP/MWh). An output-based standard in lb/MWh gross would be consistent with recent Agency rulemakings and some State actions. The option of lb HAP/TBtu steam output accounts only for boiler efficiency, ignores both the turbine cycle efficiency and the effects of energy consumption internal to the plant, and provides minimal opportunities for promoting energy efficiency at the units. The EPA has found that the second output-based format option of lb HAP/MWh is preferable as it accounts for all aspects of efficiency and provides opportunity for promoting energy efficiency for the units.

The format of lb/MWh can be measured in two ways: net and gross energy output. The net plant energy output provides the owners/operators with all possible opportunities for promoting energy efficiency and can easily accommodate both electrical and thermal (process steam) outputs. The disadvantage of a net plant energy output is that implementation could require significant and costly additional monitoring and reporting systems because the energy output that is used for internal components (and not sent to the grid) cannot be accounted for by simply installing another meter. The gross plant energy output, on the other hand, represents the energy generated before any internal energy consumption and losses are considered. Standards based on this format do not have the disadvantages of the net-based format mentioned above.

Based on this analysis, the format based on mass of HAP emissions per gross plant energy output is most desirable. Because electrical output at all power plants is typically measured directly in MWe, a format in "lb/MWh gross" is most appropriate.

Because all data provided to EPA throughout the development of the standard were in the format of lb/TBtu heat input, EPA chose to apply a conversion factor to convert the input-based emission limitation to the output-based HAP limitations. The conversion factor was based on the baseline net efficiency of the unit. The efficiency of electric utility steam generating unit is usually expressed in terms of heat rate, where efficiency of a steam generating plant is referred to as net efficiency. The EPA believes that an output-based MACT emission limitation format of lb HAP/MWh gross is appropriate and that the net efficiency value can be used to calculate the output-based emission limit. Most existing electric utility steam generating units fall in the range of 24 to 35 percent efficiency.[12] The EPA therefore decided to use 32 percent as the baseline efficiency for existing coal- and oil-fired units. Because new coal- and oil-fired units are assumed to be built for maximum efficiency, EPA believes it was appropriate to apply the 35 percent efficiency in conversion of the new unit emission limitations to the output-based limitations. The conversion factors used were:

- **Conversion factor for mass/10^{12} Btu to mass/MWh (32% combustion efficiency; the mass can be either Hg or Ni)**
  (TBtu/1,000,000,000,000 Btu) * (3.414 Btu/Wh) * (1,000,000 Wh/MWh) * (1/0.32) =
  10.7×10^{-6} TBtu/MWh
- **Conversion factor for mass/10^{12} Btu to mass/MWh (35% combustion efficiency; the mass can be either Hg or Ni)**

(TBtu/1,000,000,000,000 Btu) * (3.414 Btu/Wh) * (1,000,000 Wh/MWh) * (1/0.35) = 9.8×10^{-6} TBtu/MWh

5.2 Variability Issues

5.2.1 General discussion on variability in data. Although EPA is confident that the data available are representative of the industry, it is evident that the test report data exhibit a significant degree of variability, even within a given subcategory. The EPA decided it was necessary to develop a methodology to address the multiple sources of the observed variability in order to assure that an emission limitation value could be derived that would be achievable. The origins of variability and approaches available for addressing the apparent variability found in the test data are described below.

5.2.1.1 Origins of variability in the data. Variability is inherent whenever measurements are made or whenever mechanical processes operate. The variability in the emission test data may arise from one or more of the following areas: (1) the emission test method(s); (2) the analytical method(s); (3) the design of the unit and control device(s); (4) the operation of the unit and control device(s); and (5) the amount of the constituent being tested in the fuel.

Test and analytical method variability can be quantified by statistical analysis of the results of a series of tests. The results can be analyzed to establish confidence intervals within which the true value of a test result is presumed to lie. Confidence intervals can be estimated for multiple-run series of tests based on the differences found from one test run to the next, with only the upper confidence interval having meaning (signifying the chance of the standard being exceeded).

When testing is done at more than one unit, similar confidence intervals can be established to account for the variability from unit to unit. One can combine the test-to-test and unit-to-unit variability into a single factor that can be applied to reported test values to give an upper limit for the likely true value. One can also estimate the combined factor for any desired confidence level.

Testing for a short time may not reveal the range of emissions that would be found over extended time periods. Normal changes in operating conditions or in fuel characteristics may affect emission levels. For example, an increase in the Hg content of the fuel being fired in a unit may tend to increase the Hg emission rate from the associated stack. Mercury emissions rates may also change with unit loads. As load changes, so does gas flow rate through APCD downstream from the unit. Changes in gas flow rate may affect APCD effectiveness.

5.2.1.2 Available methods to address and incorporate variability. Variability may be addressed in a number of ways, depending on the circumstances existing within the source category. For example, different test run results can be analyzed statistically to arrive at an upper limit that represents the highest likely value for each test to be used in setting emission limits. The poorest-performing (worst-case) unit in the top 12 percent of each subcategory can be reviewed to determine the causes of poor performance with a factor then assigned that can be applied to each of the test runs. These offsets would give emission values that would not likely be exceeded over long time periods. Considering only control devices used by sources in the top 12 percent, control device performance can also be examined to determine likely emission reductions for different devices operating on different units firing different fuels. The range in emission reductions could be used to set upper limits of expected control performance; then these limits could be used, as above, to set emission limitations for each subcategory. Correlations between constituents of concern and other, perhaps more easily measured, constituents can be used to develop algorithms that incorporate variability.

The EPA found that there are two fundamentally different approaches to incorporating variability into a rule: (1) including variability in the MACT floor calculation, or (2) including variability in the compliance method. Addressing variability in the MACT floor calculation requires that all of the origins of variability be assessed and quantified into factors that can be applied into the emission limitation calculations for each subcategory's floor. Each unit used for floor calculations is assumed to operate such that its measured emission rate is increased by the amount of variability found from statistical analysis, worst-case analysis, and control device performance analysis. Each unit in the top 12 percent of its subcategory would be adjusted to reflect the uncertainty associated with the various origins of variability, and the average emission rate for these units would be used as the floor emission limitation.

Addressing variability in the compliance method would involve allowing an averaging time for compliance that would accommodate variations in pollutant emissions over time. For example, averaging over a month or a year of data will provide opportunity for variations in the amount of a constituent in the fuel to be accommodated without exceeding the emission limitation.

In trying to address the apparent sources of variability in the emissions test data, EPA tried to obtain data that reflected as many different plant configurations as would be found in the entire industry profile and conducted tests at units believed to be representative of those within the source category. The tests and measurements, typically a three-run series of manual samples taken over 1 or 2 days of testing, are limited by the emission test method's accuracy and precision, by the short duration of the test, and by differences from one run to the next and one unit to the next. Based on these limitations on the test data, EPA has decided to use both of the approaches described above for addressing test data variability.

5.2.1 Strategy to address variability for Hg. Studies available to EPA indicated that the variability of Hg emissions from coal-fired units, both instantaneous and over time, is significantly influenced by the variability in the chemical composition and properties of the coal as burned (i.e., differences in Hg content, chlorine content, and heat content of coal). The differing physical and chemical properties of Hg-containing compounds in the flue gas result in significant differences in the feasibility and effectiveness of controls for removing the compounds from flue gas. Thus, which Hg compounds are present in the flue gas impacts the amount of Hg that will be captured by control devices and how much Hg will be released in stack emissions. The studies indicated that the chlorine content of the coal has a significant impact on which Hg compounds are contained in the flue gas stream and, even more importantly, can be used as a key indicator of the type of Hg compound that will be present in flue gas. The EPA found that, when combined with other relevant data such as coal Hg content, the chlorine content of coal can be used to predict Hg emissions.

The data results from the multivariable study[11] lend support to the significance of chlorine content of coal to Hg emissions controllability. The higher the chlorine:mercury ratio, the more likely the formation of mercuric chloride (ionic or oxidized Hg) that is more readily captured by existing control devices. This chlorine:mercury ratio is independent of the coal rank as an indicator of Hg controllability. In sum, the coal chlorine content is one of the primary determinants of which Hg-containing compounds will be present, and in what amounts, in the flue gas of an individual utility unit.

The EPA determined that the stack tests in the EU/ICE database alone are insufficient to estimate the effect of fuel variability over time on the emissions of the best performing facilities. However, the EU/ICE database contains extensive data on variation in coal composition recorded over the course of a year. The EPA developed a methodology to link fuel composition data to Hg emissions in order have a better estimate of Hg emissions, and subsequently, the controllability of the emissions over time. The methodology is described below.

The units in each of the five subcategories were sorted in ascending order of stack-tested Hg emission factors, measured in units of lb/TBtu (as adjusted by a method that normalizes Hg emissions to coal heat content [F-factor Adjustment]). Accordingly, the top performing units of each subcategory were selected for further analysis.

To link fuel composition data to Hg emissions data, correlation equations were developed to represent the relationship between Hg removal fraction and chlorine concentration for each of the control configurations used by the best performing units. The steps used to develop these correlation equations are set forth below.

The control configuration of each of the best performing units was identified. The Hg removal fraction and test coal chlorine concentrations were obtained from the EU/ICE database for each of the units in the database that have one of the identified control configurations. Finally, a correlation equation was derived for each identified control configuration by fitting the following mathematical expression to the Hg removal fractions and corresponding chlorine concentrations obtained from the EU/ICE stack test database.

In the selection of the format of the correlation equation, care was taken that the mathematical expression accurately reflected the physical and chemical process by which chlorine contributes to the controllability of stack Hg emissions. The correlation equation is based on the assumption that the rate of conversion of Hg to mercury chloride is proportional to the chlorine concentration in the coal, irrespective of coal rank. With this expression, the maximum removal fraction is limited to 1, because the exponent term is always nonnegative, regardless of the chlorine concentration. This corresponds to the real-world limitation that no more than 100 percent of the Hg in flue gas can be removed (i.e., there cannot be negative Hg emissions). As the coal chlorine concentration drops to zero, the Hg removal fraction does not of necessity approach zero because some Hg removal may be achieved without reaction with chlorine. The purpose of deriving a correlation equation for each control configuration used by the top performing units was to provide a numerical means of predicting the fraction of Hg removed for the best performing sources over the entire range of fuel variability experienced over the course of a year. Correlation equations were derived for each control configuration, but were only used to predict Hg removal if they were found to have acceptable explanatory power.

To determine whether the explanatory power of each correlation equation warranted its use on a larger range of EU/ICE coal composition data, each correlation equation was validated against the EU/ICE stack test data. For each of the test chlorine concentrations in the EU/ICE stack test database, the Hg removal fraction was calculated by using the correlation equation with parameters selected to give the best fit to the data. A correlation coefficient was then calculated to evaluate the accuracy of the fit.

For each of the best performing units, unit-specific coal composition data for a one-year period were extracted from the EU/ICE database to find the coal heat content, Hg content, and chlorine content. For each set of coal composition data from the EU/ICE database, the controlled Hg emissions were calculated by multiplying uncontrolled Hg emissions by (1 – Hg removal fraction). For each of the best-performing sources, this process was repeated for each set of measured coal composition values, yielding a range of Hg emission levels for that unit over time.

The test coal composition data from the EU/ICE database (heat and Hg content) was used to calculate the uncontrolled Hg emission level. The Hg removal fraction was calculated in one of the following two ways:

(1) Where the correlation equation was found to have sufficient explanatory power, it was used to estimate the Hg removal fraction based on coal chlorine composition data from the EU/ICE database. This approach accounted for variations in the Hg, chlorine, and heat content of fuel.

(2) Where the correlation equation was a poor fit, the Hg removal fraction was based on the average Hg removal fraction observed in the EU/ICE stack tests of that unit. This latter approach yielded a constant removal fraction based upon the source test, and had the effect of reducing the variability of predicted Hg emissions. Under this approach, the measured impact of fuel variability was limited to the effect of variations in Hg and heat content, while variations in chlorine concentration were not explicitly considered.

For each of the best performing units, the calculated Hg emissions, calculated in accordance with the procedures outlined above, were then sorted from smallest to largest to obtain a cumulative frequency distribution (CFD). The 97.5th percentile value of this distribution (i.e., an emission rate that is expected to be exceeded only 2.5 percent of the time) was determined to represent the operation of the unit under worst conditions.

The EPA decided to account for unit-to-unit variability by calculating a 97.5 percent upper confidence level for the mean by use of the t-statistic. This adjustment reflects the fact that the top performing sources in the data base do not represent the full population of the best performing 12 percent of coal-fired utility units .[10]

Although fuel variability is a principal cause of emission variability, other factors also play a role in contributing to variability in Hg emissions. Analysis of fuel variability accounts for some, but not all, of the variability in the stack testing of each unit that comprises the EU/ICE database. Other drivers of variability in the test results, such as measurement error, are not included in the analysis. Intermittent maintenance events, which themselves can contribute to short-term increases in Hg emissions, also are not considered. In addition, the stack testing on which this assessment is based places artificial limitations on the variability of its results. Testing was performed with plants operating at full and constant load and without ongoing maintenance activities. Actual operation requires load-following in addition to intermittent maintenance activities. Insofar as the methodology discussed herein does not incorporate these effects, its results are likely to underestimate the reasonable worst-case emissions of the best performing facilities. For these and other reasons, EPA believes a 12-month rolling averaging period would be appropriate for the standard.

5.2.3 Strategy to address variability for Ni. The data used to determine the Ni emission limitation consisted of stack test reports from the DOE/EIA[4] effort. These emissions rates were adjusted for test-to-test run variability using the coefficient of variation (standard deviation of the data set divided by the mean of the data set) and then were adjusted for unit-to-unit variation using a student T-statistic to derive the 97.5 percentile confidence interval.

5.3 Emission Limitation Calculations

In order to determine the MACT floor emission limitations for existing units, EPA examined the population database of existing sources. Available emissions test data were divided according to the subcategorization scheme described above; first coal- and oil-fired, then the five subcategories of coal-fired units. The EPA examined the existing emissions test data to determine the individual numerical average of the test results from the best-performing 12 percent (or equivalent) of each subcategory for each regulated HAP (or surrogate). The EPA then applied variability factors as described above to derive the MACT floor limits. All test data were provided to EPA in an input-based format (lb Hg/TBtu). Therefore, EPA conducted all MACT floor calculations using the input-based format and then converted the input-based format into an output-based format (lb HAP/MWh) as a compliance option, according to the approach described in section 5.1 above. Appendix 10.2 of this document provides the detail spreadsheets listing the data used and calculations for determination of the variability factors and the emissions limitation values.

5.3.1 Mercury Emission Limitation Calculations. The EPA calculated the emission limitation for Hg for the subcategories of bituminous-fired, subbituminous-fired, lignite-fired, IGCC, and coal refuse-fired units as follows.

For bituminous-fired units, EPA had data from 32 units. Because this subcategory (i.e., nationwide population) included more than 30 units, EPA determined that the top 12 percent of the units in the subcategory would be composed of 12 percent of the number of units for which EPA had data (i.e, 4 units). The EPA determined the top four units from a ranking of units based on their emission rates from the stack test reports. The emission rates from these units ranged from 0.1062 lb/TBtu to 0.1316 lb/TBtu, with a mean of 0.1180 lb/TBtu. After applying variability as described above and rounding to 3 significant figures, EPA determined the input-based emission limitation to be 1.97 lb/TBtu. Using the conversion described in section 5.1 above (and based on 32 percent net efficiency), the input-based emission limitation of 1.97 lb/TBtu was converted to 21.0 x 10^{-6} lb/MWh as the output-based emission limitation.

For subbituminous-fired units, EPA had data from 32 units. Because this subcategory (i.e., nationwide population) included more than 30 units, EPA determined that the top 12 percent of the units in the subcategory would be composed of 12 percent of the units for which EPA had test data (i.e., 4 units). The EPA determined the top units from the ranking of the units based on their emission rates from the stack test reports. The emission rates from these units ranged from 0.4606 lb/TBtu to 1.207 lb/TBtu, with a mean of 0.7638 lb/TBtu. After applying variability as described above and rounding to 3 significant figures, EPA determined the input-based emission limitation to be 5.77 lb/TBtu. Using the conversion described in Section 5.1 above (and based on 32 percent net efficiency), the input-based emission limitation of 5.77 lb/TBtu was converted to 61.6 x 10^{-6} lb/MWh as the output-based emission limitation.

For lignite-fired units, EPA had data from 12 units. Because this subcategory (i.e., nationwide population) consisted of fewer than 30 units (in 1999), EPA determined that the top performers must include the top 5 units. The emission rates from these units ranged from 3.977 lb/TBtu to 6.902 lb/TBtu, with a mean of 5.032 lb/TBtu. After applying variability as described above and rounding to 3 significant figures, EPA determined the input-based emission limitation to be 9.24 lb/TBtu. Using the conversion described in section 5.1 above (and based on 32 percent net efficiency), the input-based emission limitation of 9.24 lb/TBtu was converted to 98.6 x 10^{-6} lb/MWh as the output-based emission limitation.

For IGCC units, EPA had data on two units. Because this subcategory (i.e., nationwide population) included less than 30 units, EPA determined that all available units would be included and were ranked based on their emission rates from the stack test reports. The emission rates from these units ranged from 5.334 lb/TBtu to 5.471 lb/TBtu, with a mean of 5.403 lb/TBtu. The EPA applied the variability factors and, with rounding to 3 significant figures, determined the IGCC input-based emission limitation to be 18.7 lb/TBtu. Using the conversion described in section 5.1 above (and based on 32 percent net efficiency), the input-based emission limitation of 18.7 lb/TBtu was converted to 200 x 10^{-6} lb/MWh as the output-based emission limitation.

For coal refuse-fired units, EPA had data from two units. Because this subcategory (i.e., nationwide population) included fewer than 30 units, EPA used all units for the calculation based on their emission rates from the stack test reports. The emission rates from these units ranged from 0.0816 lb/TBtu to 0.0936 lb/TBtu, with a mean of 0.0876 lb/TBtu. The EPA applied the variability factors as described above and with rounding to 3 significant digits, determined the input-based emission limitation to be 0.385 lb/TBtu. Using the conversion described in section 5.1 above (and based on 32 percent net efficiency), the input-based emission limitation of 0.385 lb/TBtu was converted to 4.11 x 10^{-6} lb/MWh as the output-based emission limitation.

Table 1 below summarizes the emission limitations for existing coal-fired units.

TABLE 1. Hg EMISSION LIMITS FOR EXISTING COAL-FIRED UNITS

Unit Type	Hg (lb/TBtu)	Hg (10^{-6} lb/MWh)
Bituminous-fired	1.97	21.0
Subbituminous-fired	5.77	61.6
Lignite-fired	9.24	98.6
IGCC unit	18.7	200
Coal refuse-fired	0.385	4.11

The EPA believes that the Hg emissions limitations derived above, using the test data with application of appropriate variability, provided a reasonable estimate of actual performance of the MACT floor unit on an ongoing basis.

5.3.2 Nickel Emission Limitation Calculation. The emission limit for Ni from existing oil-fired units was determined by analyzing the emissions data available. The data were obtained from the Utility RTC. The EPA examined available test data and found that ESP-equipped units can effectively reduce Ni. The Utility RTC emissions test data support the conclusion that the same control techniques used to control the fly-ash PM will also indiscriminately control Ni and that the effective removal of PM indicates removal of Ni, for a given control device. Therefore, EPA believes that ESP technology represents the MACT floor for Ni removal. The EPA has determined that the emission limitation for the oil-fired units should reflect the performance that would be expected over time for a well designed and operated ESP unit PM removal technology.

The EPA determined the value of the Ni emission limitation by ranking the stack test Ni emission rates of the 17 units for which EPA had data. The top 12 percent of the units, or 2 units, were ESP-controlled and the range of emission rates was 29.97 lb/TBtu to 357.16 lb/TBtu with a mean of 125.06 lb/TBtu. After applying variability as described above and rounding to 2 significant figures, EPA determined the input-based emission limitation to be 210 lb/TBtu. The output-based Ni emission limitation was determined to be 0.002 lb/MWh after conversion using 32 percent net efficiency. The EPA believes that these Ni emission limits are a reasonable estimate of the actual performance of the MACT floor unit on an ongoing basis.

6.0 EVALUATION OF MACT FLOOR PERFORMANCE FOR NEW UNITS

In order to develop a MACT standard for new coal- and oil- fired units, EPA used the same data described above for existing sources. The MACT floor for new sources must reflect the level of control demonstrated by the best performing similar source. Therefore, EPA evaluated the existing data to determine the best unit on which to base the emission limitation for new units.

6.1 Pollution Prevention Alternatives

In developing a MACT strategy for new units, EPA considered several prevention measures as an alternative to HAP control technology. These measures were the same precombustion techniques evaluated for existing units, which included fuel substitution, process changes, and work practices.

The feasibility of mandating which fossil fuel should be burned was evaluated from several perspectives: (1) mandating "perceived better" fuels from the same subcategory (e.g., a lower Hg content bituminous coal); (2) mandating a fuel from another subcategory (e.g., firing bituminous coal instead of lignite coal); or (3) mandating the use of natural gas. The EPA recognizes that an owner/operator, in designing a new unit, would be able to choose a perceived better coal rank (between subcategories) or a perceived better coal seam within a rank (within the subcategory) based on known issues of HAP and other pollutant control and would be able design the new unit to that fuel's characteristics. However, the economics of fuel availability would still be a determining factor as to what fuel was chosen, particularly with regard to new units co-located with existing units.

With regard to a possible EPA requirement for new sources to burn natural gas, EPA believes that availability and economics again would determine whether a source would chose to burn natural gas and that such a requirement would be unduly restrictive given the owner/operator's inability to control access to, or availability of, natural gas. For these reasons, EPA decided that mandated fuel type is not an appropriate criterion for identifying the MACT level of control for new coal-fired units.

With regard to process design alternatives and GCP, EPA believes, as discussed above in section 4.1 for existing sources, the industry has a strong economic incentive to pursue improvement in combustion and plant efficiencies and that the trends in design and technology development will continue in the direction of improvement in efficiencies such that imposition of regulatory incentives based on the existing knowledge base would be not only unnecessary but potentially restrictive. Therefore, as with existing units, EPA determined that pre-combustion techniques were not a viable regulatory strategy for the MACT standard for new coal- or oil-fired units.

6.2 Control Technology Performance Evaluations

Once EPA determined that pollution prevention alternatives would not be appropriate for the new coal- or oil-fired MACT development, EPA then evaluated the options to develop the standard for new units based on the control technology used by the top performing unit (i.e., equipment based), on the level of emission reduction that the top unit in each subcategory demonstrated, or a combination of both.

With regard to Hg and Ni emissions from new units, EPA believes that the character and levels of Hg and Ni emitted by new coal- and oil-fired units will be similar to those emitted by existing coal- and oil-fired units because the source of these pollutants is primarily the fuel and, to a limited extent, the combustion process. The EPA has no data or information that indicated that these characteristics would change in the future, particularly because EPA anticipates the use of primarily the same fossil fuel sources for new units as are being used for existing units.

The EPA is aware that the industry has the ability during the designing of new units to choose a fuel that would minimize Hg or Ni emissions production and recognizes that the MACT standard for new units should, to the extent possible, encourage the industry in that direction. The type, grades, and ranks of fossil fuel available for future use in new units will not likely change, and the availability and economics of the fuel choice for these units will likely still be a dominating factor in the design of new units. However, future technology may allow for better efficiencies in the units and, potentially, the use of a wider range of fossil fuels for a given locale or region. The EPA used the same data available for existing units which provided an evaluation of the Hg control performance of various emission control technologies that are either currently in use on coal-fired units (designed for pollutants other than Hg) or that could be applied to such units for Hg control. According to the data available to EPA, none of the existing control systems were specifically designed to remove Hg or Ni; however, most of the controls removed these pollutants to some degree. In reviewing these data with regard to new units, EPA found no control technology to be available for specifically addressing Hg for either coal- or Ni for oil-fired units, however, existing units were achieving a level of control using the current PM removal technologies such as FF and ESP units.

7.0 EMISSION LIMITATION DETERMINATION FOR NEW UNITS

As was discussed in MACT floor development for existing sources, EPA is confident that the test data available were representative of the industry; however, EPA did believe that some adjustments were justified in light of the variability in test method and in HAP-in-fuel that was discussed previously with regard to existing units. Although it was necessary to address the variability issues, the use of one data set (i.e., the best unit vs. a number of top units) negated the applicability of the unit-to-unit variability issue. Otherwise, the variability issues were addressed in the same manner as was discussed above for existing units.

The MACT for new units is based on the emission level achieved by the best-performing similar source in each subcategory. In order to develop an emission limitation for new coal- and oil-fired units, EPA ranked the existing coal- and oil-fired units from lowest to highest within each subcategory based on Hg emission rates from the stack test data. The EPA then selected the numerical performance value from the best- performing unit (or equivalent). Because test data were provided to EPA based on an input-based format (lb/TBtu), EPA conducted the emission limitation calculations using the input-based format and then converted the input-based format into an output-based format (lb/MWh) according to the approach described in section 5.1 above.

7.1 Emission Limitation format

One of EPA’s major policy strategies is to encourage energy efficiency and pollution prevention in the development of new standards. Therefore, EPA determined that the format for the new units under the standard should be based solely on an output-based format (lb/MWh) in order to encourage and reward efficiency in the operation for new units.

7.2 Variability Issues

7.2.1 General. Because the emission limitations for new units are based on the same data as existing units, the same variability issues as described in section 5.2 above were of concern. The following sections describe how EPA addressed the variability for development of emission limitations for new units.

7.2.2 Strategy for addressing variability for Hg. The evaluation of the data (see section 5.2.2 above) for existing units provided a ranking of data that had been adjusted for fuel and test method variability. The EPA decided that the rate of the best performing unit from this ranking was the appropriate value for the new unit.

7.2.3 Strategy for addressing variability for Ni. The variability and uncertainty were addressed in the same manner as for existing oil-fired units. The data from existing units was evaluated and appropriate test method variability was applied using the coefficient of variation method described above in section 5.2.3 above. The best-performing unit was chosen and that value was used for the emission limitation.

7.3 Emission Limitations Calculations for New Units

The emission limit for Hg emissions from new coal-fired units was determined by analyzing the available Hg emissions data in each subcategory. The data were obtained from the EU/ICE and included data for Hg emissions and mercury-in-coal data from all coal-fired units for calendar year 1999. The MACT emission limitation calculation was based on the performance of the top unit in the individual subcategories of bituminous coal, subbituminous coal, lignite coal, coal refuse, and IGCC (coal gas).

7.3.1 Mercury Emission Limitation Calculations for New Units. For bituminous-fired units, the best controlled unit was controlled with FF, and the Hg emissions factor was 0.132 lb/TBtu. This value was adjusted for variability as described above, and converted to the output-based format as discussed in section 5.1 above (using 35 percent efficiency factor). Consequently, the output-based Hg emissions limitation for new bituminous-fired units was determined to be 5.99 x 10^{-6} lb/MWh.

For subbituminous-fired units, the best controlled unit was also controlled with a FF, and the Hg emissions factor was 0.6633 lb/TBtu. This value was adjusted for variability as described above and converted to the output-based value (using the 35 percent efficiency factor). The output-based Hg emissions limitation for new subbituminous-fired units was determined to be 19.6 x 10^{-6} lb/MWh.

For lignite-fired units, the best controlled unit was controlled with a ESP, and the Hg emissions factor was 6.902 lb/TBtu. This value was adjusted for variability as described above and was converted to the output-based value (using the 35 percent efficiency factor). The output-based Hg emissions limitation for new lignite-fired units was determined to be 62.0×10^{-6} lb/MWh.

For IGCC units, the best controlled unit was uncontrolled, and the Hg emissions factor was 5.471 lb/TBtu. This value was adjusted for variability as described above and converted using the 35 percent efficiency factor, for an output-based Hg emissions limitation for new IGCC units of 200×10^{-6} lb/MWh. However, EPA believes that a 90 percent reduction in Hg emissions is possible from new IGCC units based on the use of carbon bed technology. The EPA believes that a 90 percent Hg reduction by a beyond-the-floor level of control for new IGCC units is achievable.[13] Consequently, the output-based Hg emissions limitation for new lignite-fired units was determined to be 20.0×10^{-6} lb/MWh (90 percent of the new unit limit determined above).

For coal refuse-fired units, the best controlled unit was controlled with a FF, and the Hg emissions factor was 0.118 lb/TBtu. This value was adjusted for variability as described above, and converted using the 35 percent efficiency factor. The output-based Hg emissions limitation for new coal refuse-fired units was determined to be 1.16×10^{-6} lb/MWh.

Table 2 below summarizes the Hg emissions limitations from new coal-fired units.

TABLE 2. Hg EMISSION LIMITS FOR NEW COAL-FIRED UNITS

Unit Type	Hg (10^{-6} lb/MWh)
Bituminous	5.99
Subbituminous	19.6
Lignite	62.0
IGCC	20.0
Coal refuse	1.16

7.3.2 Nickel Emissions Limitation Calculations for New Units. The emission limit for Ni for new oil-fired units was determined by analyzing the same emissions data available for existing units. The data were obtained from the Utility RTC. The EPA examined available test data and found that ESP-equipped units can effectively reduce Ni. The Ni emissions data mean concentration from the best-controlled oil-fired unit was used to determine the emissions limitation for new oil-fired units. The best oil-fired unit Ni emissions value from the stack test data was 0.0046 lb/TBtu. This emissions factor was then adjusted for uncertainty by applying variability factors as described above for existing units, with a resulting input-based Ni emission limit of 76 lb/TBtu. The EPA then converted the input-based value using the rationale described in section 5.1 above (using the 35 percent net efficiency factor). The resulting Ni emissions limitation for new oil-fired units is 0.0007 lb/MWh. The EPA believes that this limitation is a reasonable estimate of actual unit performance of the MACT floor unit in this case.

8.0 OTHER ISSUES

The EPA identified several issues that must be addressed in the standard with regard to the blending of fuels which fall into separate subcategories (in the case of coal-fired units) and blending of fuels which EPA has determined are exempt from the standard (in the case of oil-fired units). The EPA determined that these blending of fuels did not warrant separate subcategorization but did pose an issue with regard to compliance with any proposed or final rule.

Cogeneration units also posed an issue in that not all power (or energy) generated by the unit is transferred to the grid, making use of the output-based format problematic. The paragraphs below describe EPA's position on how to handle these issues.

8.1 Blended Coals

The EPA recognizes that many electric utility units burn more than one rank of coal, either at the same time (i.e., blending) or at separate times during a year (i.e., seasonally). Further, EPA is aware that several units burn a supplementary fuel (e.g., petroleum coke, TDF) in addition to a primary coal fuel. The EPA recognizes this practice and acknowledges the effect that coal blending (or use of supplementary fuels) will have on Hg emissions. Because this standard is not applicable to the non-regulated supplementary fuels, the standard does not provide an emission limitation for those fuels. The EPA believes that the most appropriate means to address the blending scenarios is through the compliance demonstration.

The EPA has identified several blending scenarios that might occur in the industry; blending two or more ranks of coal, blending one rank of coal with a supplementary (non-regulated fuel), or blending multiple ranks of coal with a supplementary (non-regulated) fuel. There are two potential methods for addressing the blending scenarios where two or more ranks of coal are fired. One approach would be to classify a unit based on the predominant coal it burns. For example, if 90 percent of the coal burned for the compliance period were bituminous coal, the unit would be classified as bituminous and would have to meet the Hg emission limitations for bituminous coals. A second, more equitable approach would be to develop a weighted Hg emission limit based on the proportion of energy output (in Btu) contributed by each coal rank burned during the compliance period and the coal's subcategory Hg emission limitation. The weighted emission limit would, in effect, be a blended emission limitation based on the Hg emission limitations of the subcategories of the coals burned.

The other scenarios discussed above involve blending a regulated fuel (coal, oil, coal refuse, or coal gas) with a supplementary, non-regulated fuel (e.g., petroleum coke, TDF). The application of the same methods would be appropriate for units that burn a regulated fuel with supplementary, non-regulated fuels; however, there would be no adjustment to the Hg emission limitation with regard to the supplementary, non-regulated fuel.

For example, where the predominant fuel determines which emission limitation would apply, the compliance calculation would include the energy output (Btu) of all fuels burned (including the supplementary fuel); the emissions considered would include all Hg emissions measured by the CEMS; and the unit would comply with the emission limitation associated with the subcategory of the predominant fuel. Under the other method, a weighted Hg emission limitation would be developed based on the proportions of energy output (Btu) contributed by only the regulated fuels. For example, if the unit burned bituminous, subbituminous, and petroleum coke during the compliance period, and 40 percent of the Btu output was attributable to the bituminous, 40 percent of the Btu output was attributable to the subbituminous, and 20 percent of the Btu output was attributable to the petroleum coke, the blended Hg emissions limitation would be based on the bituminous and subbituminous emission limitations in a 50/50 ratio. The compliance calculation would include the energy output (Btu) of all fuels burned (including the supplementary fuel), the emissions considered would include all Hg emissions measured by the CEMS, and the unit would comply with the blended Hg emission limitation.

The EPA recognizes that new electric utility units may still be designed to burn more than one rank of coal, either at the same time (i.e., blending) or at separate times during a period of time (i.e., seasonally). The EPA finds no reason to address blended coals differently for new units than it did for existing units. Therefore, the method of addressing blended coals with regard to the Hg emission limit calculation will remain the same for new units as is prudent for existing units. Further, EPA believes that consistency in the compliance method would be appropriate, because many utility owners/operators will at some point be addressing compliance for both new and existing units at the same facility.

8.2 Dual-fired Units

The EPA is aware that an oil-fired unit may fire oil at certain times of the year and natural gas at other times, as well as blends of residual oil and distillate oil. This blending of fuels is conducted for many reasons, most of which are economically driven with regard to the availability of fuels and the price, and may be seasonal in nature.

The EPA believes that units that burn distillate oil exclusively should be exempted from the requirements of the standard and natural gas-fired units are excluded from the definition of a covered source by the Administrator. Therefore, the requirements of the standard apply to units that fire residual oil in any proportion with another oil and to units that fire residual oil at 98 percent or greater of their annual fuel consumption, where the supplementary fuel is natural gas. The EPA believes that a cutoff of two percent fuel oil-firing would separate those units that are “fundamentally” natural gas-fired but, for startup or other operational needs, burn fuel oil. The blending scenarios that might occur for oil-fired units include the co-firing of residual oil with distillate oil and the firing of residual oil and natural gas at different times.

The unit that burns residual oil exclusively would be required to meet the oil-fired Ni emission limitation. For units that burn exclusively distillate oil, the unit would be exempted from meeting the Ni emission limitation. For units that blend residual oil with distillate oil, the unit would be required to meet the Ni emission limitation, and would include all Ni and Btus or megawatt hours generated from the use of the distillate oil in the compliance demonstration calculation. Likewise, a unit that burns residual oil during certain periods and natural gas during certain periods would include the natural gas-fired contributions (Ni and Btu or megawatt hours) in the compliance calculation.

Although EPA has not identified any other supplementary fuels burned in the oil-fired industry, we are aware that such a scenario may exist or might occur in the future. The EPA intends that where any supplementary fuel is co-fired with residual oil, the Ni and the Btus or megawatt hours contributed by the supplementary fuel be accounted for in the compliance calculation and that the unit be required to meet the Ni emission limit for existing oil-fired units.

The EPA is aware that new oil-fired units may be designed and built to fire the combination of oil and natural gas, as are existing units. The EPA believes that the reasons for not burning natural gas exclusively will continue to be based on economics or availability of fuel (i.e., seasonal considerations). Therefore, EPA intends to treat new oil-fired units that burn a combination of oil and natural gas in the same manner as existing units for compliance.

8.3 Cogeneration Units

A cogeneration facility that sells excess steam or electricity to any utility power distribution system equal to less than one-third of its potential electric output capacity and/or less than or equal to 25 MWe is considered to be either an industrial, commercial, or institutional boiler. However, a cogeneration facility that meets the above definition of an electric utility steam generating unit during any portion of a year would be subject to the standard.

For cogeneration units, steam is also generated for process use. The energy content of this process steam must also be considered in determining compliance with the output-based standard. This consideration is accomplished by taking the net efficiency of a cogeneration unit into account. Under a Federal Energy Regulatory Commission regulation, the efficiency of cogeneration units is determined from the useful power output plus one half the useful thermal output (18 CFR 292.205). To determine the process steam energy contribution to net plant output, a 50 percent credit of the process steam heat is necessary.

Therefore, owners/operators of cogeneration units would need to monitor the portion of their net plant output that is process steam so that they can take the 50 percent credit of the energy portion of their process steam net output. For example, a cogeneration unit measures its net electrical output over a compliance period, as 30,000 MWh. During the same period the unit burns coal that provides 750 billion Btu input to its furnace/boiler, and emits 0.2 lb Hg. Using equivalents found in 40 CFR 60 for electric utilities (i.e., 250 million Btu/hr input to a boiler is equivalent to 73 MWe input to the boiler; 73 MWe input to the boiler is equivalent to 25 MWe output from the boiler; therefore, 250 million Btu input to the boiler is equivalent to 25 MWe output from the boiler) the 50 percent credit could be found as follows. The net output calculation would be 750 billion Btu x (25 MWe output/250 million Btu/hr input) = 75,000 MWh equivalent electrical output from the boiler over the compliance period. Of this amount, 30,000 MWh was produced as electricity sent to the grid, leaving 45,000 MWh as the energy converted to steam for process use. Half of this amount is 22,500 MWh. The unit's Hg CEMS records a total of 0.2 lb Hg over the same compliance period. The adjusted Hg emission rate is then: 0.2 lb Hg/(30,000 MWh + 22,500 MWh) = 3.8×10^{-6} lb Hg/MWh. Cogeneration units would have to account for the process steam portion of their emissions in the same manner for Ni emissions, if applicable, as well.

9.0 REFERENCES

1. U.S.EPA. "Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units -- Final Report to Congress, Volume 1." EPA-453/R-98-004a. February 1998.

2. U.S. EPA. 1999 Electric Utility/Information Collection Effort (EU/ICE). http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html

3. Department of Energy/Energy Information Administration (DOE/EIA). "Steam-Electric Plant Operation and Design Report Database based on EIA Form, EIA-767 (1999)."

4. DOE/EIA. "Steam-Electric Plant Operation and Design Report Database based on EIA Form, EIA-767 (2001)."

5. American Society for Testing and Materials (ASTM). "D388-77, 90, 91, 95, or 98a, Standard Specification for Classification of Coals by Rank Designation." 1998.

6. U.S.EPA. "Electric Utility Steam Generating Units Section 112 Rule Making" web site: http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html

7. Singer, J. G. (ed.). Combustion, Fossil Power. Fourth Edition. Combustion Engineering, Inc., Windsor, CT. 1991. p. 1-12.

8. Federal Advisory Committee Act (FACA). Clean Air Act Advisory Committee (CAAAC). Permits, New Source Review, and Toxics Subcommittee. "Recommendations for the Utility Air Toxics MACT, Final Working Group Report." October 2002. http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html

9. DOE/EIA. "Challenges of Electric Power Industry Restructuring for Fuel Suppliers, Chapter 4. Impacts of Electric Power Industry Restructuring on Crude-Oil-Derived Fuels" pp. 64-65. DOE/EIA-0623, Distribution Category UC-950. September 1998.

10. Maxwell, W.H., U.S.EPA/OAQPS/ESD/CG. "Analysis of variability in determining MACT floor for coal-fired electric utility steam generating units." Docket A-92-55, Item No. II-B-8.

11. Multi variable Method to Estimate the Mercury Emissions of the Best-Performing Coal-Fired Utility Units Under the Most Adverse Circumstances Which Can Reasonably be Expected to Recur, West Associates, submitted at the March 4, 2003 Clean Air Act Advisory Committee Mercury MACT Working Group meeting.

12. Memorandum and attachment from W. Maxwell, EPA/CG, to Utility MACT Project Files, December 2003. Power plant efficiency table.

13. Rutkowski, M.G., M.G. Klett, and R.C. Maxwell. "The Cost of Mercury Removal from Coal-Based IGCC Relative to a PC Plant." Gasification Technologies 2002 Symposium, October 27-30, 2002, San Francisco, CA. Docket A-92-55, Item No. II-I-23.

10.0 APPENDICES

APPENDIX 10.1

LIST OF ACRONYMS

APCD- Air pollution control device

ASTM - American Society for Testing and Material

Btu - British Thermal Units

CAA - Clean Air Act

CEMS - Continuous emissions monitoring system

CFD - Cumulative frequency distribution

CO - Carbon monoxide

DOE/EIA - Department of Energy, Energy Information Administration

EPA - Environmental Protection Agency

EPRI PISCES - Electric Power Research Institute, PISCES Study

ESP - Electro-static precipitator

EU/ICE - Electric Utility/ Information Collection Effort

FBC - Fluidized bed combustor

FF - Fabric filters

FGD- Fluidized gas desulfurization

FR- Federal Register

gal - Gallon

GCP - Good combustion practices

HAP - Hazardous air pollutants

Hg - Mercury

HHV - Higher heat value

IGCC - Integrated gasification combined cycle

lb - Pound

MACT - Maximum achievable control technology

MWe - Megawatt electricity

MWh - Megawatt hour

NESHAP- National Emissions Standards for Hazardous Air Pollutants

Ni - Nickel

NO_x - Nitrogen oxides

NSPS - New Source Performance Standards

PC - Pulverized coal

PM - Particulate matter

RTC - Electric Utility Report to Congress

SDA - Spray dryer adsorber

SO_2 - Sulfur dioxide

Syngas - Synthetic coal gas

TBtu - Trillion British thermal units

TDF - Tire-derived fuel

APPENDIX 10.2

Data and Emission Limitation Calculations

See Excel Spreadsheet: MACT Floor Data.xls

APPENDIX 10.3

Mercury Speciation Analysis by Coal Rank

See Excel Spreadsheet: Hg Speciation by fuel.xls