MEMORANDUM

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SUBJECT: Revised Methodology for Estimating Impacts from Industrial, Commercial, Institutional Boilers at Area Sources of Hazardous Air Pollutant Emissions

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1.0 INTRODUCTION

The purpose of this memorandum is to discuss the methodology used to estimate the costs, emission reductions, and secondary impacts from industrial, commercial, and institutional boilers at area sources of hazardous air pollutants (HAP). These impacts were calculated for existing units and new units projected to be operational three years after the rule is expected to be promulgated. The results of the impacts analysis are presented for both the most stringent regulatory option evaluated and the regulatory option contained in the final rule. The development of the maximum achievable control technology (MACT) floor and Generally Achievable Control Technology (GACT) level of control, projection of new units, and a detailed description of the cost equations used to estimate costs for various control technologies is presented in other memoranda.[1,2,3] This memorandum is organized as follows:

- 1.0 Introduction
- 2.0 Overview of Regulatory Options
- 3.0 Estimating Cost Impacts
- 4.0 Methodology for Estimating Emission Reductions
- 5.0 Methodology for Estimating Secondary Impacts
- 6.0 References

2.0 OVERVIEW OF REGULATORY OPTIONS

Four control options were considered for existing boilers at area sources of HAP. A description of the four options is described below.

2.1 Existing Units

- Option 1E represents the option where all boilers, regardless of fuel type or size, must meet mercury and CO numerical emission limits based on MACT and PM numerical emission limits based on GACT. PM GACT was identified to be a multiclone for existing units.

- Option 2E represents the same emission limits as discussed in 1E above for large units (equal to or greater than 10 mmBtu/hr). Small units are exempt from numerical limits and instead are required to meet a work practice standard of a biennial tune-up. All facilities are required to conduct an energy assessment.

- Option 3E represents the option in which all coal boilers equal to or greater than 10 mmBtu/hr must meet mercury and CO numeric emission limits based on MACT. All biomass and liquid boilers equal to or greater than 10 mmBtu/hr must meet a CO numerical emission limit, based on MACT. All facilities with a large boiler are required to conduct an energy assessment. Small boilers are exempt from numeric emission limits for all pollutants, but are required to meet a work practice standard of a biennial tune-up. There are no numerical emission limits for PM under this option for any size or type of unit.

- Option 4E represents the option which is discussed most prominently in the preamble. In this option, all coal boilers equal to or greater than 10 mmBtu/hr must meet mercury and CO numeric emission limits based on MACT. All biomass and liquid boilers must comply with GACT for urban HAP, which is a boiler tune-up. All facilities with a large boiler are required to conduct an energy assessment. Small coal-fired boilers are exempt from numeric emission limits for all pollutants, but are required to meet a work practice standard of a biennial tune-up. There are no numerical emission limits for PM under this option for any size or type of unit.

2.2 New Units

Four control options were considered for new boilers at area sources of HAP. A detailed description of the four options is described below.

- Option 1N represents the option where all boilers, regardless of fuel type or size, must meet mercury and CO limits based on MACT and PM numerical emission limits based on GACT. GACT for new units is based on PM limits in the New Source Performance Standards (NSPS) for Industrial, Commercial, and Institutional Boilers (40 CFR part 60 subparts Db, Dc).

- Option 2N represents the same emission limits as discussed in 1N above for large units (equal to or greater than 10 mmBtu/hr). Small units are exempt from numerical emission limits and instead are required to meet a work practice standard of a biennial tune-up.

- Option 3N requires all coal boilers, regardless of size, must meet mercury and CO limits based on MACT and PM numerical emission limits based on GACT. All biomass and liquid boilers, regardless of size, must meet CO limits based on MACT and PM numerical emission limits based on GACT.

- Option 4N - represents the option in which all coal boilers equal to or greater than 10 mmBtu/hr must meet mercury and CO numeric emission limits based on MACT. All biomass and liquid boilers must comply with GACT , which is a tune-up. Small boilers coal-fired are exempt from numeric emission limits for all pollutants, but are required to meet a work practice standard of a biennial tune-up. All units greater than 10 mmBtu/hr have PM emission limits based on GACT. The emission limit changes for units greater than 30 mmBtu/hr.

3.0 ESTIMATING COST IMPACTS

For each option, a percentage of units in each model unit were assumed to require control devices in order to meet the limit when the baseline emissions for the model unit exceeded the MACT floor emission limit applicable to each model. A detailed description of the options is described below. A summary table comparing the overall capital and annualized costs of option 4E for existing units and option 4N for new units is presented in Table 1. The cost, emission reduction, and secondary impacts summarized here and in Sections 4, and 5, respectively, reflect the impacts for new units when using the NSPS limit of 0.03 lb/mmBtu for PM. The equations used to estimate the control, testing, monitoring, and work practice costs are discussed in another memorandum.[3] The following logic was used to apply control, testing, and monitoring costs to each boiler:

3.1 Option 1E

Control Cost Impacts

Mercury Control

A new fabric filter installation was expected to achieve the mercury emission limits in the final rule. Where baseline mercury emissions were found to be greater than the MACT floor, the cost of a fabric filter was estimated for a portion of the boilers represented by the model unit. Based on the data used in the MACT floor analysis, a fraction of units in each subcategory meeting the MACT floor for Hg was estimated.

For boilers designed to burn biomass one of the boilers was meeting the floor and the other unit was not meeting the floor. In the cost impacts analysis, 50 percent of the biomass units were estimated to install a fabric filter to meet the floor. For boilers designed to burn coal, 86 percent of units were achieving the MACT floor emission limit for coal, so a new fabric filter was estimated to be installed at 14 percent of the existing coal-fired boilers. For liquid fuel units, there were no area source boilers with emission test data available for mercury. In the absence of other information about the distribution of units that would require a fabric filter to be installed, this cost impacts analysis assumes that 50 percent of the liquid fuel units would install a fabric filter to meet the mercury limit.

CO/Organic HAP Control

Organic HAP and carbon monoxide can be controlled by either improving the combustion efficiency of the unit, or installing an oxidation catalyst on the exhaust of a combustion unit. The control strategy necessary to meet the MACT floor emission limit will vary depending on the magnitude between the baseline emissions and the CO MACT floor.

Most boilers are designed to operate with CO emissions at or near 400 parts per million (ppm). A boiler tune-up was estimated in the cost impacts analysis if the unit's baseline emissions exceeded the floor for carbon monoxide (CO), but were less than or equal to 400 ppm @ 3% O_2. The combustor design of the boilers in the area source inventory is not known and this impacts analysis assumes that all areas source boilers firing solid fuels have a stoker combustor design since this is the predominant combustor design in the major source boiler inventory. The baseline emissions for area source boilers in all fuel categories are less than 400 ppm, and so it is assumed that combustion controls, either a basic tune-up or a more advanced burner replacement or installation of a linkageless boiler management system, can achieve the MACT floor emission limits. No oxidation catalysts are estimated to be required to meet the MACT floor emission limits.

Based on the emission test data used to calculate the MACT floor for CO, 29 percent of units burning coal are exceeding the MACT floor and these units would be expected to install a linkageless boiler management system to comply with the CO limits. For units burning biomass, 69 percent of the units are exceeding the MACT floor emission limits, and so 69 percent of the units are estimated to install a linkageless boiler management system. For units burning liquids, 10 percent of the units are exceeding the floor and this cost impacts analysis assumes these units will install a new low NOx replacement burner in order to meet the CO limits. The units not expected to install these advanced controls are expected to conduct an annual tune-up to maintain in compliance with the proposed CO limit overtime.

Particulate Matter Control

For all units that were not expected to install a fabric filter for mercury control, the cost impacts analysis for this option assumes that the unit would install a multiclone to achieve the GACT emission limits for PM. Based on the current MACT floor analysis, 44 percent of coal units and 50 percent of liquid units would install a multiclone. Existing biomass units not expected to install a fabric filter would also install a multiclone. Base on the current MACT floor analysis, 50 percent of existing biomass units would install a multiclone.

Testing and Monitoring Cost Impacts

Testing and monitoring requirements varied depending on the equipment installed on the unit to control emissions, the design capacity of the model unit, and the fuel category of the model unit.

Testing Costs

All boilers designed to burn solid fuels were expected to conduct an annual compliance test for PM, Hg, and CO. The cost to conduct stack tests for these three pollutants was estimated to be $15,000 per year.

Boilers designed to burn liquid fuels were expected to conduct an annual compliance test for PM and CO. In lieu of a stack test boilers designed to burn liquid fuels were expected to conduct fuel analysis, or report fuel analyses received from a fuel supplier for chlorine and Hg. Conducting stack tests for PM and CO was estimated to be $13,000 per year and the cost to conduct fuel analysis for Hg was estimated to be $600 per year. Although solid fuels are eligible to comply with the rule through fuel analysis in lieu of stack testing, when the mercury content of the fuel is below the MACT floor emission limit, this cost estimate conservatively assumed that only units designed to fire liquid fuels would use this compliance alternative. The methods and data sources used to estimate testing and monitoring costs are discussed in other memoranda.[3]

Monitoring Costs

Various monitor configurations were installed based on the size of the unit and the pollution control devices expected to be installed to achieve the MACT floor emission limits. For units expected to install a fabric filter, an annualized cost of $9,700 for a bag leak detection monitor was included in the cost analysis. For units that did not install a bag leak detector, an annualized cost of $14,660 for an opacity monitor was included in the cost analysis.

Fuel Savings Impacts

This cost analysis includes an estimate of energy savings for every unit that is expected to install controls to improve combustion, or conduct an annual tune-up or energy assessment. The Department of Energy has conducted energy assessments at selected manufacturing facilities and reports that facilities can reduce fuel/energy use by 10 to 15 percent by using best practices to increase their energy efficiency. Many best practices are considered pollution prevention because they reduce the amount of fuel combusted which results in a corresponding reduction in emissions from the fuel combustion. Further boiler tune-ups have been shown to improve the efficiency of a boiler between 1 and 5 percent, depending on the age of the unit and the time lapse since the previous tune-up. Other combustion controls such as upgrading burners and installation of an LBMS are also expected to improve the efficiency of the unit, thus reducing fuel consumption. This cost analysis assumes an annual fuel savings of 1 percent. The energy savings is estimated using Equation 1:

$$\text{Annual Fuel Savings (mmBtu/yr)} = DC * CF * Op_{hours} * EG \qquad \textbf{(Equation 1)}$$

Where:
DC = unit design capacity (mmBtu/hr)
Op_{hours} = annual operating hours, assumed 8400 (hours/year)
EG = Efficiency gain, estimated to be 1%
CF = annual average capacity factor, 0.5 for liquid and 0.65 for coal and biomass

After the fuel savings for each boiler was calculated, the both industrial and commercial prices for coal, #2 distillate fuel oil, and #6 residual fuel oil were obtained from the EIA.[3] The EIA data reported fuel prices as $/ton for coal, and cents per gallon for fuel oil. The higher heating values were obtained from Table C-1 of the EPA Mandatory Reporting Rule (40 CFR part 98 subpart C) and the higher heating values were used to convert the fuel prices to a standard unit of measure, $ per mmBtu. Using the distribution of SIC codes reported in the 13-state boiler inspector inventory, the model units were distributed to an industrial or commercial sector, and then the appropriate fuel price was multiplied by the calculated fuel savings. This cost analysis only estimates the fuel savings from units in the coal and liquid fuel categories. A fuel savings was not estimated for units in the biomass fuel category since the price of biomass fuels is variable, and often biomass is an on-site industrial byproduct instead of a purchased fuel.

3.2 Option 2E

Option 2E follows the same logic for estimating control costs as option 1E outlined above, with the exception of small units (less than 10 mmBtu/hr). In option 2E, the only cost estimated for small units is the cost of an annual tune-up for each boiler. No testing and monitoring costs were included in option 2E for small units. Option 2E also includes the cost of an energy assessment at every area source facility, approximately 91,339 facilities. As discussed in the memorandum for Estimating Control Costs from Major Source Boilers and Process heaters, the cost of an energy assessment ranges from $75,000 for industrial-scale energy assessments to between $2,000 and $5,000 per energy assessment for institutional and commercial-scale assessments.[4] The facility's classification of either an industrial or commercial facility was assigned using the distribution of SIC codes in the 13-state boiler inspector inventory. The cost of each type of assessment was annualized over 5 years at 7 percent to obtain an annualized cost estimate.

3.3 Option 3E

Option 3E includes control device and testing/monitoring cost estimation for mercury and CO from large coal units. As mentioned in option 1E, 56 percent of large coal units, or 321 boilers are expected to install a fabric filter in order to meet the mercury limit. In addition, 29 percent of large coal units are expected to install advanced combustion controls in order to meet the CO limit. This analysis uses the cost of a linkageless boiler management system to estimate the costs of advanced combustion control. The remaining 71 percent of large coal units are expected to meet the CO limit with a tune-up. The testing and monitoring costs for large coal units include a test for CO and mercury, as well as a bag leak detection system for the 321 boilers that are expected to install a fabric filter. There are no numerical PM emission limits under this option, and so no additional testing costs for PM or opacity monitoring costs were assessed in the cost impacts analysis for this option.

Under option 3E liquid and biomass boilers are not subject to numerical emission limits for mercury and there are no costs included in the impacts analysis to install fabric filters or conduct mercury fuel analysis or stack testing. Large liquid and biomass boilers are subject to numerical emission limits for CO. This cost impacts analysis estimates that all the biomass and liquid fuel units can meet the CO emission limits by conducting an annual tune-up. These large units must also conduct testing and monitoring activities for CO to demonstrate compliance with the numerical emission limits.

Option 3E exempts small boilers from numerical emission limits. Instead these units must conduct a work practice standard of a biennial tune-up. The cost impacts analysis does not include any additional testing and monitoring requirements for these small boilers.

Finally, option 3E proposes that all facilities with large boilers conduct an energy assessment. For this cost impacts analysis one large boiler per facility was assumed, or 13,268 facilities estimated to conduct an assessment. Similar to the discussion under option 2E, the cost of the assessment ranged from $75,000 for industrial-scale energy assessments to between $2,000 and $5,000 per energy audit for institutional and commercial-scale assessments.[2]

3.4 *Option 4E*

Option 4E includes control device and testing/monitoring cost estimation for mercury and CO from large coal units. As mentioned in option 1E, 14 percent of large coal units, or 80 boilers are expected to install a fabric filter in order to meet the mercury limit. In addition, 19 percent of large coal units are expected to install advanced combustion controls in order to meet the CO limit. This analysis uses the cost of a linkageless boiler management system to estimate the costs of advanced combustion control. The remaining 81 percent of large coal units are expected to meet the CO limit with a tune-up. The testing and monitoring costs for large coal units include a test for CO and mercury, as well as a bag leak detection system and oxygen monitoring for the 80 boilers that are expected to install a fabric filter. There are no numerical PM emission limits under this option, and so no additional testing costs for PM or opacity monitoring costs were assessed in the cost impacts analysis for this option.

Under option 4E liquid and biomass boilers are not subject to numerical emission limits for mercury or CO and there are no costs included in the impacts analysis to install control equipment or conduct mercury or CO fuel analysis or stack testing. This cost impacts analysis includes the cost of a biennial tune-up for all the biomass and liquid fuel.

Option 4E exempts small coal-fired boilers from numerical emission limits. Instead these units must conduct a work practice standard of a biennial tune-up. The cost impacts analysis does not include any additional testing and monitoring requirements for these small boilers.

Finally, option 4E proposes that all facilities with large boilers conduct an energy assessment. For this cost impacts analysis one large boiler per facility was assumed, or 13,268 facilities estimated to conduct an assessment. Similar to the discussion under option 2E, the cost of the assessment ranged from $75,000 for industrial-scale energy assessments to between $2,000 and $5,000 per energy assessment for institutional and commercial-scale assessments.[2]

3.5 *Option 1N*

New area source boilers are subject to an NSPS (40 CFR part 60 subparts Db, Dc) to regulate emissions of PM, NOx and SO2. The cost impacts analysis considered controls that would likely be installed to comply with the NSPS and includes an estimate of any additional control, testing and monitoring costs that would not be already conducted to meet the requirements of the NSPS. Based on a review of the NSPS, this analysis assumes all biomass boilers greater than 30 mmBtu/hr will have an ESP control installed as the baseline to meet the NSPS PM limits; all coal boilers greater than 75 will have an FF and wet scrubber installed to meet PM and SO2 limits; all coal boilers between 30 and 75 will have a Fabric Filter and use low sulfur coal to meet PM and SO2 limits, and all liquid boilers greater than 30 will have an FF installed to meet PM limits. The NSPS does not regulate PM for units less than 30 mmBtu/hr.

Mercury Control

A new fabric filter installation was expected to achieve the mercury emission limits in the final rule. Where baseline mercury emissions were found to be greater than the MACT floor, the cost of a fabric filter was estimated for a portion of the boilers represented by the model unit. All new boilers, regardless of size or fuel, were expected to install a fabric filter in order to meet the mercury limits under this option. Comparing these mercury control requirement to the expected controls under the NSPS, all biomass boilers are expected to install a fabric filter to meet the mercury limit and all liquid and coal boilers less than or equal to 30 mmBtu/hr are expected to install a fabric filter to meet the mercury limit.

CO/Organic HAP Control

New boilers are expected to be equipped with new and efficient burners, and it was assumed that an annual tune-up could achieve the CO numeric emission limit for all sizes and types of boilers. Other advanced combustion controls were not considered as a control alternative for new boilers. As mentioned under 1E, the control strategy necessary to meet the MACT floor emission limit will vary depending on the magnitude between the baseline emissions and the CO MACT floor.

Particulate Matter Control

Under this option all units are expected to install a fabric filter for mercury control, which has a co-benefit of reducing PM emissions, as well as other non-mercury metallic HAP. No additional control costs were estimated for PM control at new boilers.

Testing and Monitoring Cost Impacts

Testing and monitoring requirements varied depending on the equipment installed on the unit to control emissions, the design capacity of the model unit, and the fuel category of the model unit.

Testing Costs

All boilers designed to burn solid fuels were expected to conduct an annual compliance test for PM, Hg, and CO. The cost to conduct stack tests for these three pollutants was estimated to be $15,000 per year.

Boilers designed to burn liquid fuels were expected to conduct an annual compliance test for PM and CO. In lieu of a stack test boilers designed to burn liquid fuels were expected to conduct fuel analysis, or report fuel analyses received from a fuel supplier for chlorine and Hg. Conducting stack tests for PM and CO was estimated to be $13,000 per year and the cost to conduct fuel analysis for Hg was estimated to be $600 per year. Although solid fuels are eligible to comply with the final rule through fuel analysis in lieu of stack testing, when the mercury content of the fuel is below the MACT floor emission limit, this cost estimate conservatively assumed that only units designed to fire liquid fuels would use this compliance alternative. The methods and data sources used to estimate testing and monitoring costs are discussed in other memoranda.[3]

Monitoring Costs

Various monitor configurations were installed based on the size of the unit and the pollution control devices expected to be installed to achieve the MACT floor emission limits. For units expected to install a fabric filter, an annualized cost of $9,700 for a bag leak detection monitor was included in the cost analysis. For units that did not install a bag leak detector, an annualized cost of $14,660 for an opacity monitor was included in the cost analysis.

3.6 *Option 2N*

Option 2N follows the same logic for estimating control costs as option 1N outlined above, with the exception of small units (less than 10 mmBtu/hr). In option 2N, the only cost estimated for small units is the cost of an annual tune-up for each boiler. No testing and monitoring costs were included in option 2N for small units

3.7 Option 3N

Option 3N includes identical requirement for coal units as outlined under option 1N. Under option 3N liquid and biomass boilers are not subject to numerical emission limits for mercury and there are no costs included in the impacts analysis to install fabric filters for mercury control or conduct mercury fuel analysis or stack testing. Liquid and biomass boilers are subject to numerical emission limits for CO. This cost impacts analysis estimates that all the biomass and liquid fuel units can meet the CO emission limits by conducting an annual tune-up. These units must also conduct testing and monitoring activities for CO to demonstrate compliance with the numerical emission limits.

Option 3N also includes a numerical PM emission limit for coal, biomass, and liquid boilers, based on the NSPS limits applicable to each of these categories. Since all coal units are subject to mercury emission limits, they are expected to meet a PM GACT limit of 0.03 lb/mmBtu without any additional control requirements. The NSPS PM limit for biomass is 0.03 lb/mmBtu, which is based on the performance of an electrostatic precipitator (ESP). Since biomass units greater than 30 mmBtu/hr are already subject to this limit under the NSPS, this cost analysis applies the costs for an ESP to units less than or equal to 30 mmBtu/hr. The NSPS PM limit for liquids is also 0.03 lb/mmBtu. Based on the calculated average baseline emission factors analysis distillate liquids are expected to meet that limit without any additional control.[5] However residual liquid units are expected to install a fabric filter to meet the PM emission limit.

Under option 3N, all boilers less than or equal to 30 mmBtu/hr are estimated to incur costs to test for PM and CO, at an estimate cost of $14,000 per year. Boilers greater than 30 mmBtu/hr will incur PM stack testing costs under the NSPS. Coal boilers are estimated to incur additional costs to test for mercury and the cost to conduct tests for PM, CO, and Hg is estimated to be $19,000 per year.

3.8 Option 4N

Option 4N includes mercury and CO emission limits for coal units greater than 10 mmBtu/hr. Under option 4N liquid and biomass boilers are not subject to numerical emission limits for mercury or CO and there are no costs included in the impacts analysis to install add-on controls for mercury or CO control or conduct mercury or fuel analysis or stack testing. This cost impacts analysis estimates an biennial tune-up to meet GACT requirements for all the biomass and liquid fuel units.

Option 4N also includes a numerical PM emission limit for coal, biomass, and liquid boilers. The emission limits are set for units between 10 mmBtu/hr and 30 mmBtu/hr respectively. Coal units in this range are expected to meet emission limits of 0.42 lb/mmBtu. These mid-range Biomass boilers are subject to an emission limit of 0.069 lb/mmBtu, and liquid units in this range must meet an emission limit of 0.03 lb/mmBtu. All units greater than or equal to 30 mmBtu/hr, regardless of fuel type, are expected to meet a PM GACT limit of 0.03 lb/mmBtu. Coal units are expected to meet this limit using the same device installed for mercury control. Biomass units are expected to meet the PM emission limit using an electrostatic precipitator (ESP). Based on the calculated average baseline emission factors analysis distillate liquids are expected to meet that limit without any additional control.[5] However residual liquid units are expected to install a fabric filter to meet the PM emission limit.

Under option 4N, all boilers from 10 mmBtu/hr to 30 mmBtu/hr are estimated to incur costs to test for PM, at an estimate cost of $8,000 per year. Boilers greater than 30 mmBtu/hr will incur PM stack testing costs under the NSPS. Coal boilers are estimated to incur additional costs to test for mercury and CO the cost to conduct tests for PM, CO, and Hg is estimated to be $19,000 per year.

3.9 Summary of Cost Impacts

In the final rule, option 4E is the option selected for existing boilers and option 4N is the option selected for new boilers. Table 1 summarizes the costs of the promulgated option for new and existing boilers at area sources of HAP. Appendix A of this memorandum provides a detailed summary of the costs for each model unit.

Table 1: Summary of Costs of Promulgated Options

Costs shown in $\$10^6$ (2008) with capital recovery estimated at 7%

Type of Unit	Option	Number of Boilers	TAC	TAC considering fuel savings	Testing & Monitoring TAC	Control TAC	Control TCI
New	4N	6,779	$48	$51.3	$25	$36	$100
Existing	4E	182,677	$436	$51.6	$7	$429	$1,295

4.0 METHODOLOGY FOR ESTIMATING EMISSION REDUCTIONS

This section discusses the methodology used to estimate emission reductions from boilers at both existing and new facilities and it presents a summary of the results for the regulatory options 1E/1N and 4E/4N.

4.1 Emission Reductions from Existing Boilers

Each model area source boiler was assigned baseline emissions based on the calculated baseline averages for existing major source combustion units in the same size and fuel subcategory. The development of area source model units and the procedures and results of the baseline emissions analysis is presented in other memoranda.[5-6]

Emission Reductions for Option 1E

Emission reductions for all pollutants were calculated on a ton per year basis. Emission reductions of Hg and CO were calculated by subtracting the baseline emissions assigned to each model unit from the MACT floor (or GACT) emission limits corresponding to the subcategory for each model boiler. A detailed discussion of the procedures and results of the MACT floor analysis is presented in another memorandum.[1]

For all units expected to install a fabric filter to meet the mercury MACT floor emission limits, this fabric filter achieves a co-benefit of reducing emissions of PM and non-mercury metallic HAP. To calculate the PM emission reductions from units expected to install a fabric filter, the baseline emissions assigned to each model boiler were subtracted from the calculated average baseline emission factor corresponding to a fabric filter level of control in the same fuel category. For example, the PM baseline emission factor for uncontrolled or multiclone-equipped biomass boilers is 0.27 lb/mmBtu, and the calculated baseline emission factors for biomass boilers equipped with a fabric filter is 0.004 lb/mmBtu. The emission reductions were estimated using the difference of these two factors, or 0.266 lb/mmBtu. The methodology used to calculate average baseline emission factors for different fuel and control configurations is discussed in another memorandum.[5] It was assumed that the remaining boilers that did not install a fabric filter will install a cyclone or multiclone to reduce PM emissions. Multiclones were identified as a GACT level of control for PM. Emission reductions for units expected to install a multiclone were estimated by multiplying the baseline emissions of each model unit by the expected PM control efficiency of a multiclone specific to the fuel category. These control efficiencies for various control devices are detailed in another memorandum.[5] Model units with a design capacity greater than 10 mmBtu/hr were expected to already have a multiclone installed as a baseline level of control, so no additional PM emission reductions were estimated from these units, unless the unit installed a fabric filter for mercury control.

To estimate the reductions in other non-mercury metallic HAP, the percent reduction in filterable PM was calculated for each model boiler expected to install a fabric filter for mercury control. This percent reduction was multiplied by the baseline emissions for each of the non-mercury metallic HAP. Since fabric filters capture fine particulate, this analysis assumes that each model boiler would achieve an identical percent reduction from baseline emissions for each non-mercury metallic HAP as was achieved for PM. For model boilers that were expected to install a multiclone to meet the PM GACT limit, a 10 percent reduction was estimated for non-mercury metallic HAP.

PM2.5 emissions comprise a fraction of total filterable PM emissions depending on the fuel combusted and control device configuration installed on the unit. The methods used to derive the contribution of PM2.5 to overall filterable PM are presented in other memoranda.[5] To calculate emission reductions for PM2.5 for each model boiler, the emission reductions for PM were multiplied by the applicable PM2.5 fraction.

For any boiler conducting a tune-up or installing advanced combustion controls such as a replacement burner or linkageless boiler management system, a one percent gain in combustion efficiency was estimated, resulting in an estimated one percent emissions reduction of all pollutants. Efficiency gains reduce fuel use, and in turn, emissions of hazardous air pollutants.[8] A one percent reduction in emissions for these pollutants was estimated by multiplying the baseline emissions for each unit by a factor of 0.01.

To convert emission reductions from an emission rate on a heat input basis to an annual emission rate, Equation 2 was used:

Annual Emission Rate (tpy) = ER_{HI} * 0.0005 * Op_{hours} * CF **(Equation 2)**

Where:

ER_{HI} = emission rate (lb/mmBtu)
0.0005 = conversion factor, lbs per ton
Op_{hours} = annual operating hours, assumed 8760 (adjusted using capacity factor)
CF = annual average capacity factor, 0.68

To convert emission reductions from a concentration basis to an annual emission rate, Equations 3 and 4 were used:

Annual Emission Rate (tpy) = ER_C * 0.000001 * Q_S * 60 * Op_{hours} * MW * 0.0026 * 0.0005 * (20.946 – O_2) / (20.946 – Std O_2) * CF **(Equation 3)**

Where:

ER_C = emission concentration (ppm @ 3% O_2)
0.000001 = conversion factor, ppm to parts
Q_S = exhaust flowrate (dscfm)
60 = conversion factor, minutes to hours
Op_{hours} = annual operating hours reported in 2008 survey (hours/year)
MW = molecular weight of pollutant, in lb per lb-mole
0.0026 = conversion factor, lb-mole per dry standard cubic foot of gas
0.0005 = conversion factor, lb per ton
20.946 = percentage of oxygen in ambient air
O_2 = percentage of oxygen assumed in exhaust gas
Std. O_2 = 3 percent oxygen in standardized emission concentration for final rule.
CF = annual average capacity factor, 0.68

Annual Emission Rate (tpy) = ER_C * 0.0283 * Q_S * 60 * Op_{hours} * 0.000000001 * 0.0022 * 0.0005 * (20.946 – O_2) / (20.946 – Std O_2) * CF **(Equation 4)**

Where:

ER_C = emission concentration (ng/dscm @ 7% O_2)
0.0283 = conversion factor, dry standard cubic meter per dry std. cubic foot
Q_S = exhaust flowrate (dscfm)
60 = conversion factor, minutes per hour
Op_{hours} = annual operating hours reported in 2008 survey (hours/year)
0.000000001 = conversion factor, ng to g
0.0022 = conversion factor, g per lb
0.0005 = conversion factor, lb per ton
20.946 = percentage of oxygen in ambient air
O_2 = percentage of oxygen assumed in exhaust gas
Std O_2 = 7 percent oxygen in standardized emission concentration for final rule.
CF = annual average capacity factor, 0.68

Converting concentrations to an annual emission rate required an oxygen concentration and exhaust flowrate estimated for each specific fuel type. The development of these assumptions and estimates is presented in another memorandum.[4]

Emission Reductions for Option 4E

The same calculations discussed for estimating emission reductions for option 1E were applied to all large coal boilers. For small model boilers, the emission reductions were based on a one percent gain in efficiency expected from the biennial tune-up work practice standard. For large biomass and liquid units no add-on controls for PM or mercury are expected since these units are not subject to numerical emission limits for PM or Hg. Instead, a similar one percent gain in efficiency is expected to occur as a result of conducting an annual tune-up or installing advanced combustion controls necessary to meet the CO numerical limit in each category. Efficiency gains reduce fuel use, and in turn, emissions of hazardous air pollutants. A one percent reduction in all types of emissions was estimated by multiplying the baseline emissions for each unit by a factor of 0.01. A summary of the estimated emission reductions at existing units for all options is located in **Appendix B-1**.

4.2 Emission Reductions from New Boilers

Based on industrial and commercial fuel consumption projections from the EIA and a history of boiler installation dates in the boiler inspector inventory, there are 6,779 new area source boilers expected to come on-line by 2013.[7] These new projected boilers are expected to fire biomass, coal, and liquid fuels. An average (mean) design capacity of area source boilers firing similar fuel type, in the same size category, and in the same sector (industrial or commercial) was estimated to develop new model units representative of the existing boiler inventory. New model units were assigned baseline emissions in the same manner as existing area source model units. The projection of new model area source boilers and the procedures and results of the baseline emissions analysis is presented in other memoranda.[2]

As discussed in Section 3.4, the NSPS for Industrial, Commercial and Institutional Boilers (40 CFR part 60, subparts Db, Dc) (NSPS) were reviewed to identify the expected baseline level of control for projected new units. Then, the average baseline emission factor corresponding to the expected level of control and fuel category was assigned to each new model boiler. New biomass boilers larger than 30 mmBtu/hr were expected to install an ESP; new coal boilers larger than 75 mmBtu/hr were expected to install a fabric filter and wet scrubber; new coal boilers between 30 and 75 mmBtu/hr would only have a fabric filter installed and were expected to meet the SO2 limits in the NSPS by using coals with a low sulfur content; new boilers larger than 30 mmBtu/hr and combusting liquid fuels were expected to install a fabric filter. All new boilers less than 30 mmBtu/hr would have no add-on controls. For this impacts analysis, it was assumed that all new solid fuel units would be stokers, since stoker boilers are the most common type of solid fuel boilers and all new units would have NOx control installed as a baseline control, regardless of fuel. Based on the EIA fuel projections, all new coal boilers are projected to be less than 10 mmBtu/hr and the only 49 model boilers firing biomass are expected to exceed 30 mmBtu/hr.

Emission Reductions for Option 1N

After an appropriate baseline level of control was determined for each model unit, an average baseline emission factor was calculated for existing units within the same fuel category and having the same level of control was assigned to each model boiler. The NSPS specifies PM and SO2 limits for new solid- and liquid-fired combustion units based on heat input. It was assumed that all new solid and liquid units would be constructed to meet these limits and those limits were used as baseline emission values, where applicable. For units less than 30 mmBtu/hr, the baseline emissions for PM were estimated assuming the unit was uncontrolled and the target PM emission limit from the NSPS was used as the GACT level of control. The baseline emissions for each unit were subtracted from the new source MACT floor for Hg and CO and GACT emission limit for PM corresponding to each unit's subcategory. The same calculations discussed in Section 4.1 of this memo were used to estimate the reductions for new units.

Emission Reductions for Option 4N

For new coal boilers, the emission reductions were calculated using the same methods discussed for Option 1N above. For new biomass boilers less than 30 mmBtu/hr, emission reductions for PM were calculated by subtracting the PM NSPS emission limits from a baseline emission factor representing uncontrolled units. Since an ESP is not expected to be very effective at capturing mercury emissions, mercury emissions reductions from all biomass units were estimated based on a one percent efficiency improvement, resulting from annual tune-ups or other combustion controls expected to occur in order to demonstrate compliance with CO emission limits. For new biomass boilers greater than or equal to 30 mmBtu/hr, there were no estimated additional PM or non-Hg metallic HAP emission reductions since these larger biomass boilers are already expected to be in compliance with a PM NSPS limit using an ESP.

New residual liquid boilers less than 30 mmBtu/hr were expected to install a fabric filter to meet the PM emission limit. Since a fabric filter is effective at capturing fine particulate, additional emission reductions for mercury were calculated by subtracting the average baseline emission factor for heavy liquid boilers equipped with a fabric filter from the average baseline emission factor corresponding to an uncontrolled heavy liquid unit.

The average baseline emission factor for PM at uncontrolled distillate liquid units is less than the NSPS emission limit for liquid units. As a result, no additional PM, Hg, or non-Hg metallic HAP emission reductions were estimated from installing additional PM controls. Instead, these reductions were estimated based on a one percent efficiency improvement, resulting from annual tune-ups or other combustion controls expected to occur in order to demonstrate compliance with CO emission limits.

Under this option, new small units do not qualify for the same tune-up work practice standards that apply to existing units since it is expected that new units can be designed to allow for stack test diameters that would be compatible with EPA test methods. A summary of the estimated emission reductions at for all new source options is located in **Appendix B-2**.

5.0 METHODOLOGY FOR ESTIMATING SECONDARY IMPACTS

Secondary impacts include the solid waste and electricity required to operate air pollution control devices, as well as the additional energy savings resulting from improved combustion controls or work practices required by the NESHAP. This section documents the inputs and equations used to estimate these secondary impacts, and it summarizes the impacts at existing units under promulgated regulatory option 4E and new units under promulgated regulatory option 4N. Table 5-1 summarizes the secondary impacts of this promulgated NESHAP.

Appendices C-1 and C-2 present a detailed breakdown of the secondary waste and energy impacts from each subcategory of existing and new boilers, respectively.

Table 5-1:. Summary of Secondary Impacts

Impact	New Units (Option 4N)	Existing Units (Option 4E)
Solid Waste (tons/yr)	540	1,800
Purchased Electricity (kW-hr/yr)	8.0 million	25.4 million
CO2 Emissions from Electricity (tons/yr)	5,300	16,900
Energy Savings* (tBtu/yr)	2.3	19.6

* Energy savings is calculated for units in the coal and liquid subcategories.

The secondary impacts were calculated using algorithms and assumptions described in another memorandum.[3] These algorithms and assumptions were applied to the existing boilers, where the baseline emissions for each unit exceeded the promulgated MACT floor emission limit. For new units, the algorithms and assumptions were applied to model units representing units expected to come online between 2010 and 2013, when the baseline emissions for each model exceeded the promulgated MACT floor or GACT emission limit for new units. The methodology used to assign baseline emission factors to new and existing units are discussed in another memorandum.[5]

5.1 Solid Waste Impacts

Solid waste is generated from collecting dust and fly ash in fabric filters or ESP control devices. Solid waste impacts were estimated for every unit expected to install a fabric filter to meet mercury emission limits, or install an ESP to meet PM emission limits. The total national solid waste amounts in Table 5-1 were determined by adding the per unit solid waste estimates for all new and existing units, respectively. To estimate the solid waste contribution from each of these control devices, the variables were calculated based on characteristics reported for each model unit. The calculations used to estimate each variable and the quantity of solid waste generated are provided in another memorandum.[3]

The solid waste (dust, fly ash) generated by the use of an electrostatic precipitator was calculated when an electrostatic precipitator was determined to be necessary to meet the GACT emission limits for PM. Estimates of the solid waste collected in an ESP was based on several variables including: exhaust flow rate from the combustion unit to the control device (acfm); the inlet loading of particulate matter to the control device (gr/acfm); operating hours (hr/year) and the efficiency of the control device required to meet the PM emission limits in the promulgated NESHAP.

The solid waste generated from the collection of dust and fly ash in a fabric filter was calculated when a fabric filter was determined to be necessary to meet the promulgated NESHAP emission limits for particulate matter and/or mercury. The calculation required the use of three variables, including: exhaust flow rate from the combustion unit to the control device (dscfm); operating hours (hr/year) and the inlet loading of particulate matter to the control device (gr/acfm).

5.2 Electricity Impacts

The amount of electricity required to operate a control device was calculated for an electrostatic precipitator and fabric filter. These impacts were assessed for every unit that was estimated to require particulate matter control. Electricity requirements are one output of the cost algorithms used in the analyses, so no additional calculations were necessary. For some units, an electrical demand from multiple control devices was estimated. The total national electricity demand in Table 5-1 was determined by adding the per unit solid waste estimates for all new and existing units, respectively. To estimate the electricity demand from each of these control devices, a set of variables were calculated based on characteristics assigned to each model unit. The constants, variables, and calculations used to estimate each variable and the electricity demand to operate the control devices are provided in another memorandum.[3]

5.3 Greenhouse Gas Emissions from Electricity Usage

Since Greenhouse Gases are generated from electricity production, an estimate of carbon dioxide emissions was generated for the electricity impacts of the add-on air pollution control devices. The total electricity impact amount was multiplied by the national average carbon monoxide emission factor for carbon dioxide emissions from EPA's 2005 e-GRID to obtain the expected annual carbon dioxide emissions.[9] No carbon dioxide emissions were estimated for boilers conducting a boiler tune-up since no electricity impacts were estimated for those units.

5.4 Energy Savings Impacts

The energy savings from combustion controls such as low NOx burners or linkageless boiler management systems, and work practice standards, including a tune-up, and implementing the energy audit findings with a short-term payback can improvements in efficiency, thereby reducing fuel consumption. Although these combustion improvements have been documented to achieve efficiency gains between 5 and 10 percent from the baseline operating conditions, this secondary impacts analysis estimates a 1 percent efficiency gain, to be conservative and consistent with the assumptions made in Section 3.1 of this memorandum. Quantifying the exact gains in efficiency from each of these work practice standards is difficult, and may depend on the baseline operating efficiency of each unit.

Section 3.1 discusses the fuel savings impacts in terms of annualized cost savings to each boiler, and the national energy savings presented in Table 5-1 of this section follows the same methodology as was discussed in Section 3.1 and reflect the savings from boilers in the coal and liquid fuel categories only.

5.5 Estimating Secondary Impacts for Regulatory Options 4E/4N

Regulatory Options 4E for existing and 4N for new units are both described in detail in Section 2 of this memorandum. For the secondary impacts analysis at existing units under option 4E, the waste and electricity impacts were only assessed for large units (those greater than or equal to 10 mmBtu/hr) that are in the coal subcategory. Secondary impacts of solid waste and electricity were not assessed for the liquid and biomass subcategories because these boilers were not subject to PM or Hg numerical emission limits and were not expected to install add-on controls. Energy savings were estimated for all units firing anything other than biomass since all units were expected to conduct a tune-up or install combustion controls.

For new units under option 4N, the solid waste and electricity impacts were assessed for any size unit firing coal, liquid, or biomass, using the NSPS limit of 0.03 lb/mmBtu for PM. A one percent energy savings was estimated for all units firing coal or liquids that were estimated to require a tune-up to meet the CO limits from new boilers. Both tune-ups and combustion controls improve the efficiency of the unit, thereby reducing energy consumption.

6.0 REFERENCES

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7. U.S. Department of Energy. Energy Information Administration. Annual Energy Outlook 2006 (Early Release) with Projections to 2030. Figure 3. Energy Consumption by Fuel, 1980-2030 (quadrillion Btu).

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