RTI INTERNATIONAL | Memorandum

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SUBJECT: Methodology for Estimating Cost and Emissions Impact for Coal- and Oil-Fired Electric Utility Steam Generating Units National Emission Standards for Hazardous Air Pollutants

This memorandum describes the development of cost and emissions impacts estimates for electric utility steam-generating units that will be subject to a National Emission Standard for Hazardous Air Pollutants (NESHAP). The estimates support regulations for mercury (Hg) from coal-fired units and nickel (Ni) from oil-fired units.

MEMORANDUM OUTLINE

1.0 INTRODUCTION

Costs were estimated for controls to reduce Hg emissions from coal-fired units and Ni emissions from oil-fired units. Costing was based on adaptations of methods given in the EPA Air Pollution Control Cost Manual[1] (Manual). The Manual uses sizing information, equipment cost curves, and factors associated with specific controls to arrive at overall capital and annual costs. Where costs are not available, or to check current equipment costs, vendor contacts can be made to get such costs. Four major elements are included in the costing: direct and indirect capital costs, and direct and indirect annual costs (including annualized costs for capital recovery). Direct capital costs include purchased equipment (control device plus auxiliary equipment, instrumentation, sales tax, and freight) and installation (foundation and supports, handling and erection, electrical, piping, insulation, and painting). Site preparation and buildings are not usually required, but would be included with direct capital costs. Indirect capital costs include engineering, construction and field expense, contractor fees, start-up, performance test, and allowance for contingencies. Direct annual costs are comprised of operating labor (operator and supervisor), operating materials, maintenance labor and materials, replacement parts, utilities (such as electricity or compressed air), and waste disposal. Indirect annual costs include overhead, administrative charges, property tax, insurance, and capital recovery (the annualized cost of money borrowed to purchase and install the control system). The annualization of capital recovery is based on estimated equipment life and interest rate. For fabric filters (baghouses) and electrostatic precipitators (ESP), equipment life is estimated at 20 years. For spray-dryer adsorbers (SDA) life is estimated at 15 years. Interest rates are taken as 7 percent for all equipment.

Because the costing is for equipment to be installed at existing plants, extra costs are required to accommodate difficulties in working around equipment and structures already in place. These extra costs appear as a retrofit factor included in the total capital investment. Values for retrofit factors use here are 1.4 for baghouses and ESP, and 1.2 for SDA units.

For coal fired units, costs were estimated using a population of 1,143 units (furnace/boiler combinations) ranging in equivalent rated electrical capacity from 16 MW[1] to 1,426 MW. Oil-fired units were costed based on 218 units ranging in size from 25 MW to 1,028 MW.

Incremental impacts associated with installing controls include power to operate them, solid waste (ash) that must be disposed of, water consumption where applicable, and wastewater treatment. All of these quantities are estimated as part of the costing methods so that annual operating costs can be found. Impacts due to compliance monitoring, recordkeeping, and reporting are not given here. They can be found in Form SF-83 that is part of the rulemaking package.

A major impact is the emission reduction attributed to installation of controls. These reductions and the costs and other impacts are given on a nationwide basis. The modeling used for estimation is based in part on the individual units, but the estimate for any single unit may not be accurate. However, in the nationwide aggregate, estimates are expected to be reasonable.

Tables 1 and 2 show the results for costs and impacts associated with controlling Hg emissions from coal-fired electric utility units and Ni from oil-fired electric utility units, respectively. Table 3 shows totals for the two fuel types.

While environmental impacts are given for all units, not all are projected to require costs for new or upgraded controls. Units that are below the proposed emission limits would not require equipment changes. For coal-fired units, 719 are estimated to require equipment changes. For oil-fired units, 189 are estimated to require equipment changes. These numbers are equivalent to 63 percent and 87 percent of the coal- and oil-fired units, respectively.

Appendix A contains the spreadsheets used for generating costing equations and environmental impacts for coal- and oil-fired units. The spreadsheets are of simple construction, but contain large amounts of information. Rows are used for units (one row per unit) and columns are used for input data (e.g., unit MW) and for cost or impact calculations (e.g., capital cost).

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[1] Some boiler/furnace units are smaller than the equivalent of 25 MW, but are paired with similar units to serve a 25 MW (or greater) generator.

Table 1. Estimated incremental impacts for coal-fired utility units, rounded, in millions except for mercury reduction

Unit type	Capital cost, 1999 $	Annual cost, 1999 $/y	Energy usage, kWh/y	Solid waste, tons/y	Mercury reductions, tons/y (good units under limit)	Mercury reductions, tons/y (all units at limit)	Water usage, gal/y
Bituminous	4,609	728	89	0.194	14.4	13.3	208
Subbituminous	607	92	4	0.009	2.0	-1.6	0
Lignite	61	9	0	0.001	0.4	-0.5	0
Blends	657	101	5	0.009	2.1	1.6	0
IGCC	0	0	0	0.0	0.0	0.0	0
Coal refuse	57	18	33	0.082	0.1	0.05	117
Total	5,991	948	131	0.300	19.0	12.9	325

"Good units" are estimated to emit below proposed limits without adding new controls.

Table 2. Estimated Incremental impacts for oil-fired utility boiler emission reductions, rounded, in millions except for nickel reductions

Impact	Capital cost, 2001 $	Annual cost, 2001 $/y	Energy, kWh/y	Solid waste, tons/y	Ni reduction tons/y
PM control, all plants	2,190	417	1,292	0.002	620

Table 3. Total estimated incremental impacts for coal- and oil-fired utility boiler emission reductions, rounded, in millions except for mercury and nickel reductions

Impact	Capital cost	Annual cost	Energy	Solid waste	Water usage	Mercury reductions, current rate for good units	Mercury reductions, all units at limit	Nickel reductions
Units	1999 $	1999 $/y	kWh/y	tons/y	gal/y	tons/y	tons/y	tons/y
	8,181	1,365	1,423	0.302	325	19.0	12.9	620

2.0 METHODOLOGY FOR ESTIMATING COST AND EMISSION IMPACTS

2.1 Costs for Coal-fired Units

A variety of control strategies is available for removing mercury from flue gas. Data from the 1999 information collection request (ICR) sent to all electric utility owners and operators showed year-long Hg-in-coal concentrations and, for 79 units (total of 80 stack test reports, one tested twice), Hg removal results for the last flue-gas treatment device before the unit's stack. These devices included ESP, baghouses, cyclones, particle scrubbers, wet flue-gas desulfurization (FGD) scrubbers, and SDA desulfurization systems. Although only 79 units were tested, all units have some form of particulate matter (PM) control and many have controls for sulfur oxides and/or nitrogen oxides.

Examination of the data showed that effectiveness of these devices varied, and appeared to be affected by factors such as coal rank, coal constituents, and upstream controls (e.g., selective catalytic reduction [SCR], and selective non-catalytic reduction [SNCR]). Because of the complexity of selecting specific systems for each of the 1,143 electric utility units, and with limited resources available for cost and impacts estimation, a simplified methodology was used for estimating costs and impacts.

For each unit, an estimate was made of its 1999 emission level based on modeling with information from the 1999 ICR (see memorandum Mercury Emission Estimates for Coal-fired Power Plants, from C. Allen to J. Cole, December 2003; note that the memorandum and its associated spreadsheet use an emission limit of 0.52 lb Hg/TBtu for waste fuels, which was later changed to 0.38 lb Hg/TBtu and used for costs and impacts estimates). This estimate (minus the amount of the limit) was divided by the projected emission limit for the subcategory applicable to the unit to provide a ratio. Depending on the ratio, the unit was assigned a multiplier representing a fraction of the cost of a new fabric filter and auxiliaries sized for the unit. For example, if a bituminous unit emitted at the rate of 3 lb Hg/TBtu with a limit of 2 lb Hg/TBtu, the ratio would be 0.5, or 50 percent greater emissions than allowed. For a ratio of 1.5 or below (but above 0; units with a ratio of 0 or less would not require further reductions), the assigned multiplier was set at 0.3. The unit was estimated to be able to come into compliance through refurbishing, upgrading, or otherwise altering its existing control equipment or process for 30 percent of the cost of a new fabric filter and auxiliaries. This 30 percent level represents judgement as to how much money would be required to take whatever action is needed. For ratios between 1.5 and 3, or 3 and 9, the multipliers were 0.5 or 1, respectively. For ratios above 9, the multiplier and associated baghouse cost were replaced with the cost of an SDA/baghouse sized to the unit.

The Manual was used to cost fabric filters at three sizes for each coal rank: 100, 500, and 975 MW for bituminous, subbituminous, and lignite. The costs per MW (capital and annual) were plotted against unit size in MW and equations were developed from the plots. The resulting six equations (three for capital costs and three for annual costs) were used as appropriate for the three ranks of coal, the size of the unit, and the amount of excess emissions. For example, if the unit given above were 500 MW, the equivalent capital cost to meet the emission limit would be as shown in the following equation:

Capital cost = [8,847 x ln(500) +14,386] x 500 x 0.3 = $10.4 million (1999 dollars).

The term in brackets represents the equation derived for bituminous coals as used for a 500 MW unit. Because the equation is on a MW basis, it must be multiplied by the unit size of 500 MW. Unit incremental capital costs for the fabric filter equations range from about $55/kW to $85/kW in 1999 dollars. Appendix B gives the equations used for cost and impact estimates.

Costing for SDA units was based on detailed information in a National Lime Association (NLA) document.[2] The document provides capital and annual costs for two 500 MW systems burning low-sulfur Appalachian bituminous coal and low-sulfur Powder River Basin subbituminous coal respectively. Four cases were costed: new units with both coals and retrofit units with both coals. Unit costs for these units ranged from $122/kW to $163/kW.

Costs attributed to the rule are incremental, representing only costs added to a plant's existing costs for emission control. For example, costs of solid waste handling and disposal for an existing ESP would be increased by a relatively small amount for additional ash collected after upgrading, not by the entire amount of ash handled in the upgraded unit.

2.2 Environmental Impacts for Coal-fired Units

The nationwide environmental impacts shown in Table 1, incremental increases in electricity, solid waste, and water (and reductions in mercury), were developed as part of the cost estimates. All of these incremental increases are required to estimate annual operating and maintenance costs and are included in spreadsheets based on the Manual. As with capital and annual costs, equations were developed from the costing spreadsheets to estimate impacts on a MW basis. For the 500 MW example given above, incremental electricity usage is found from the following equation:

$$\text{Electricity} = [-56.224 \times \ln(500) + 791.88] \times 500 = 221{,}235 \text{ kWh/y.}$$

Water usage for SDA units is derived from the NLA document. Because the spray drier evaporates all of the water used for slurrying calcium sorbent, no dedicated wastewater stream exists.

2.3 Costs for Oil-fired Units

Unlike coal-fired utility units, most oil-fired units do not have PM controls. To meet the proposed Ni limitations, most units will require the installation of an ESP or fabric filter. Although the first fabric filter on a full-scale, oil-fired utility unit was installed in the 1960s, the filters have not become popular because of safety concerns. For this reason, all units not having an ESP were assumed to require one at 90 percent efficiency to meet the emission limit. As with coal-fired units, equations were developed to estimate costs as a function of unit size in MW. The equations were based on unit sizes of 150, 370, and 700 MW. Costs were also estimated for 25, 50, and 70 MW units as a check on smaller units. Because most units do not have an ESP, the incremental costs include essentially all capital and annual items at full cost. Table 5 gives the equations used for costing.

Credit was given for units already equipped with an ESP. Similarly, for units having cyclones or multicyclones, new ESP units were assumed to require an efficiency of 80 percent. Assuming a 60-MW unit without an existing ESP or multicyclone, estimated capital cost was found from the following equation:

$$\text{Capital cost} = [-162{,}853 \times \ln(60) + 813{,}007)] \times 60 = \$8{,}773{,}842.$$

Many of the plants have two or more relatively small units. These plants were examined and, where it appeared feasible, units were combined to exhaust to one large ESP rather than having a separate ESP for each unit. This strategy tended to reduce estimated capital and annual costs at appropriate plants, and is a likely action for plants to take.

2.4 Environmental Impacts for Oil-fired Units

As with coal-fired units, environmental impacts were estimated as part of the costing spreadsheets. For ESP units, only electricity and solid waste added to environmental impacts. For both impacts, the spreadsheet values were nearly constant across ESP sizes: 28,873 kWh/y-MW and 0.163 tons/y-MW for solid waste. For example, a 60 MW plant would use the following amount of electricity:

$$\text{Electricity usage} = 28{,}873 \times 60 = 1{,}732{,}380 \text{ kWh/y}$$

Note that severe time constraints in preparing the cost and impact estimates (and this memorandum) have led to using engineering judgement to a greater degree than would ordinarily be used. It is likely that the error bounds for these estimates are broader than usual. Also engineering judgement was used in the emission factor bin assignments that lead to the emission totals taken from the 1999 EU/ICE data national emissions model. This technique for choosing emission factors occasionally caused apparently similarly configured units with similar fuel consumption to have significantly different emission totals..

3.0 References

1. U.S. Environmental Protection Agency. *EPA Air Pollution Control Cost Manual*, sixth edition. EPA -452-02-001. Office of Air Quality Planning and Standards, Research Triangle Park, NC. January 2002.

2. National Lime Association. *Dry Flue Gas Desulfurization Technology Evaluation*, Project Number 11311-000, September 26, 2002

Appendix A

Cost and Emissions Impacts Calculations

See Excel Spreadsheets: Costs-impacts Hg coal-docket.xls,
Costs- impacts Ni oil-docket.xls, and
ESP util-oil-docket.xls

Appendix B

Equations for Cost and Impacts Estimates

Equations for Cost and Impacts Estimates

Cost and impacts equations for coal-fired utility units

Coal rank	**Capital cost, \$/MW**	**Annual cost, \$/(y-MW)**
Bituminous	8,847 x ln(size) + 14,386	1295.5 x ln(size) + 2,638.6
Subbituminous	8,256.1 x ln(size) + 20,570	3.2078 x (size) + 9,106.6
Lignite	8,047.5 x ln(size) + 27,528	1,233 x ln(size) + 4,430.7

	Electricity, kWh/(y-MW)	**Solid waste, tons/(y-MW)**	**Water, gal/(y-MW)**
Bituminous	-56.224 x ln(500) + 791.88	0.725 x (size)	289,000 x (size)
Subbituminous	-58.806 x ln(size) + 828.25	1.112 x (size)	359,834 x (size)
Lignite	-58.806 x ln(size) + 828.25	1.317 x (size)	414,375 x (size)

Cost and impacts equations for oil-fired utility units

	Capital cost, \$/MW	**Annual cost, \$/(y-MW)**
size < 83 MW	-162,853 x ln(size) + 813,007	-23,373 x ln(x) + 118,878
size > 83 MW	-24,890 x ln(size) + 204,138	-3,538.9 x ln(size) + 31,394

	Electricity, kWh/(y-MW)	**Solid waste, tons/(y-MW)**
all sizes	28,873 x (size)	0.163 x (size)