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BART Analysis for
PSNH Merrimack Station Unit MK2

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1. INTRODUCTION

PSNH Merrimack Station has two coal-fired steam-generating boilers that operate nearly full time to meet baseload electric demand. Unit MK2 is a wet-bottom, cyclone-type boiler with a heat input rating of 3,473 MMBtu/hr and an electrical output of 320 MW. Installed in 1968, this generating unit is equipped with selective catalytic reduction to remove oxides of nitrogen (NO_X) formed during the combustion process. Two electrostatic precipitators operate in series to capture particulate matter (PM) in the flue gases. Also, construction is nearing completion on a limestone forced oxidation scrubber system that will reduce sulfur dioxide (SO_2) emissions. Retrofit options for this unit are limited because the facility already has controls in place for these major pollutants of concern. Only a few emission control technologies are compatible with the type of boiler design employed, and space for new retrofits is very limited.

2. CURRENTLY AVAILABLE RETROFIT TECHNOLOGIES, POTENTIAL COSTS, AND OTHER ENVIRONMENTAL AND ENERGY IMPACTS

2.1 Retrofit Technologies for NO_X Control

Because of the current boiler design, the only NO_X emission control technology options available and potentially applicable to Unit MK2 are selective non-catalytic reduction and selective catalytic reduction.

Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion technology that involves injecting ammonia or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_X in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected, the mixing of the reagent in the flue gas, the residence time of the reagent within the required temperature window, the ratio of reagent to NO_X, and the sulfur concentration in the flue gas. (Sulfur in the flue gas, originating from the sulfur content of the fuel, can combine with ammonia to form solid sulfur compounds such as ammonium bisulfate that may become deposited in downstream equipment.) NO_X reductions of 35 to 60 percent have been achieved through the use of SNCR on coal-fired boilers operating in the United States.

Selective Catalytic Reduction (SCR)

SCR is another post-combustion technology that involves injecting ammonia into the flue gas in the presence of a catalyst to reduce NO_X to nitrogen and water. The SCR reactor can be located at various positions in the process, including upstream of an air heater and particulate control device, or downstream of an air heater, particulate control device, and flue gas desulfurization system. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia-to-NO_X ratio, inlet NO_X concentration, space velocity, catalyst design, and catalyst condition. NO_X emission reductions of about 75 to 90 percent have been obtained with SCR on coal-fired boilers operating in the U.S.

2.1.1 Potential Costs of NO_X Controls

The estimated costs of NO_X emission controls for SNCR and SCR at Merrimack Station Unit MK2 are presented in Table 2-1. These estimates are based on assumptions used in EPA's Integrated Planning Model for the EPA Base Case 2006 (V.3.0), for retrofitting an electric generating unit (EGU) the size of Unit MK2. For SNCR, the total annual cost is estimated to be about $5,110,000, or $593/ton of NO_X removed. For an SCR system, the total annual cost is estimated to be $5,070,000, or $312/ton. Stated costs are for year-round operation.

Table 2-1. Estimated NO_X Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost $	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
SNCR	12.1	3,880,000	4,780,000	5,110,000	593
SCR	117.8	37,710,000	1,910,000	5,070,000	312

Estimates are derived from USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006. Costs are scaled for boiler size. All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 320-MW unit with 80% capacity factor and 2,243 million kWh annual generation. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on an estimated 8,613 tons of NO_X removed for SNCR and an estimated 16,269 tons of NO_X removed for SCR.

Because Unit MK2 already has SCR controls in place, the listed costs serve for comparative purposes only. In 1998, PSNH estimated that its SCR costs would be about $400/ton for year-round operation and about $600/ton for operation limited to the ozone season (May 1 through September 30). These costs are approximately equal to $530/ton and $790/ton, respectively, in 2008 dollars. PSNH currently operates Unit MK2 full time in order to meet NO_X RACT requirements.

Year-round operation is EPA's presumptive norm for BART (applicable to EGUs of 750 MW capacity or greater) for units that already have seasonally operated SCRs. Assuming that operating costs are proportional to operating time, the difference in cost between year-round and seasonal SCR operation for Unit MK2 is about $3,300,000, based on PSNH's 1998 cost estimates. The cost differential could be about half that amount, if based on the more recent generic estimates presented in Table 2-1.

2.1.2 Other Environmental and Energy Impacts of NO_X Controls

SNCR and SCR both use urea or anhydrous ammonia. Ammonia is a regulated toxic air pollutant in New Hampshire. Facilities using these technologies must limit their ammonia emissions, which may be released either in their flue gases or as fugitive emissions from the handling and storage of urea or anhydrous ammonia. A facility must also maintain a risk management plan if the quantities of stored ammonia exceed the applicable regulatory threshold.

Ammonia from SNCR that becomes entrained in the fly ash may affect the resale value or disposal cost of the ash. Ammonia in the flue gas may produce a more visible plume, depending on the ammonia concentration in the gas stream. High ammonia concentrations in the boiler from SNCR can react with sulfate to form ammonium bisulfate, which deposits on the economizer, air heater, and other surfaces. Ammonium bisulfate can also plug filter bags in a baghouse. SNCR may generate nitrous oxide emissions, a greenhouse gas.

With SCR, the formation of ammonium bisulfate may be exacerbated by the ability of this catalyst-based technology to oxidize SO_2 to SO_3, resulting in higher sulfate concentrations than would otherwise exist. Ammonium bisulfate formation can be reduced by controlling excess ammonia and using catalysts that minimize SO_2 oxidation. The air heater and other surfaces where the ammonia bisulfate may deposit must be acid washed periodically. Acid washing helps to maintain the efficiency of the air heater and prevents plugging to allow the free flow of flue gases through it. An SCR may also require a fan upgrade to overcome additional pressure drop across the catalyst. The increase in fan capacity consumes a small amount of energy. (In the case of Unit MK2, the existing fan was sufficient to accommodate the additional pressure drop.)

NO_X emission reductions provide environmental and public health benefits beyond visibility improvement – most notably, reductions in acid rain and ground-level ozone. NO_X is a chemical precursor to ozone formation and is one of the primary compounds contributing directly to acid rain formation. A decrease in acid rain production improves water quality and the health of ecosystems sensitive to low pH.

2.2 Retrofit Technologies for PM Control

PM control technologies available and potentially applicable to Unit MK2 are electrostatic precipitators, fabric filters, mechanical collectors, and particle scrubbers.

Electrostatic Precipitators (ESPs)

Electrostatic precipitators capture particles through the use of electrodes, which are electrical conductors used to make contact with non-metallic parts of a circuit. An ESP consists of a small-diameter negatively charged electrode (usually a set of individual wires or a grid) and a grounded positively charged plate. In operation, a strong electric charge from the negatively charged electrode sets up a one-directional electric field. When particle-laden gases pass through this electric field, the particles become charged and are then drawn to the positive collecting surface (the plate), where they are neutralized. The particles are then collected by washing or knocking the plate, causing the particles to fall into a collection hopper. Existing electrostatic precipitators are typically 40 to 60 percent efficient. New or rebuilt ESPs can achieve collection efficiencies of more than 99 percent.

For older units, options for upgrading an ESP system include: replacement of existing control systems with modern electronic controllers; replacement of old-style wire and plate systems inside the ESP with new, rigid electrode systems; addition of new ESP fields; or addition of entire new units (in series). The feasibility of any particular upgrade will be influenced by spatial limitations or design constraints on a case-by-case basis.

Fabric Filters

Fabric filtration devices, or baghouses, incorporate multiple fabric filters/bags inside a containment structure. These devices work on the same principal as a vacuum cleaner bag.

The particle removal efficiency of the fabric filter system depends on a variety of particle and operational parameters. The physical characteristics of particle size distribution, particle cohesion, and particle electrical resistivity are important variables. Operational parameters affecting collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, and cleaning intensity. The structure of the fabric filter, filter composition, and bag properties also affect collection efficiency. Collection efficiencies of baghouses may exceed 99 percent.

Mechanical Collectors and Particle Scrubbers

Mechanical collectors, such as cyclones, are most effective at collecting coarse particulate matter (i.e., particles with a diameter of 10 micrometers or larger). Finer particles escape cyclones along with the flue gases. For this reason, mechanical collectors are generally most useful when used in conjunction with other pollution control equipment. The typical collection efficiency of mechanical collectors is about 85 percent for larger particle sizes.

Scrubbing systems involve the injection of water and/or chemicals into the flue gas to wash unwanted pollutants from the gas stream through physical or chemical absorption/adsorption. Scrubbing systems have been shown to reduce PM_{10} emissions by 50 to 60 percent but are generally less effective for removal of fine particles.

Because mechanical collectors and particle scrubbers are more costly and less efficient than other control options (i.e., ESPs, baghouses), these lower-performing technologies are rarely used today for removing particulate matter from power plant emissions. Consequently, mechanical collectors and scrubbers are not considered further in this analysis for the control of PM emissions.

2.2.1 Potential Costs of PM Controls

Table 2-2 presents cost data for PM controls as developed from NESCAUM's *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. Approximate cost ranges are provided for two types of ESPs and two types of fabric filters applicable to a retrofit installation the size of Unit MK2. Capital and operating costs are based on flue gas flow rates in actual cubic feet per minute (acfm).

Table 2-2. Estimated PM Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost ($)	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
Dry ESP	73-194	23.3-62.1 million	1.1-1.9 million	3.0-7.1 million	100-240
Wet ESP	73-194	23.3-62.1 million	0.6-1.6 million	2.6-6.8 million	90-230
Fabric filter – reverse air	82-194	26.4-62.1 million	1.6-2.4 million	3.8-7.6 million	130-260
Fabric filter – pulse jet	58-194	18.6-62.1 million	2.2-3.1 million	3.7-8.3 million	130-280

Reference: NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 320-MW unit with 80% capacity factor and flue gas flow rate of 1.36 million acfm. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on 29,850 tons of PM removed for ESPs and 29,759 tons of PM removed for fabric filters.

The costs for ESPs and fabric filters are of similar magnitude, with total annual costs ranging from about \$2.6 million to \$8.3 million, or \$90 to \$280 per ton of PM removed. Because Unit MK2 already has two dry ESPs installed and operating, the tabulated costs are useful for comparative purposes only. For facilities with existing ESPs, typical equipment replacement costs to upgrade performance may be in the range of \$10,000 to \$30,000 per MW. (M. Sankey and R. Mastropietro, "Electrostatic Upgrade Strategy: Get the Most From What You Have," Hamon Research-Cottrell, Inc., April, 1997.)

2.2.2 Other Environmental and Energy Impacts of PM Controls

PM controls collect particulate matter, or fly ash, suspended in the flue gases. In some cases, the fly ash is injected back into the boiler, an arrangement that improves boiler efficiency by recapturing the residual heating value of the fly ash. If the fly ash is not reinjected, it must be either landfilled or reclaimed, e.g., as a supplement in concrete production or as a component in other manufactured products.

2.3 Retrofit Technologies for SO_2 Control

SO_2 control technologies available and potentially applicable to Unit MK2 are scrubber systems for flue gas desulfurization, and use of low-sulfur coal.

Flue Gas Desulfurization

Scrubber systems use chemical reagents to "scrub" or "wash" unwanted pollutants from a gas stream. Flue gas desulfurization (FGD) processes based on this technology concept are classified as either wet or dry. Wet scrubbers are more commonly used at power plants to control acid gas emissions. Scrubbers of all types may be effective for the removal of particulate matter, mercury, sulfur dioxide, and other air pollutants.

In the wet FGD process, an alkaline reagent is applied in liquid or slurry form to absorb SO_2 in the flue gas. A PM control device is always located upstream of a wet scrubber. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. Wet regenerative (meaning the reagent material can be treated and reused) FGD processes are an attractive option because they allow higher sulfur removal rates and produce minimal wastewater discharges.

For coal-fired power plants, the reagent is usually lime or limestone; and the reaction product is calcium sulfite or calcium sulfate. The solid compounds are collected and removed in downstream process equipment. Calcium sulfate (gypsum) sludge produced in FGDs can be recycled into saleable byproducts such as wallboard, concrete, and fertilizer. Sulfate products that are not recycled must be landfilled.

SO_2 removal efficiencies for existing wet limestone scrubbers range from 31 to 97 percent with an average of 78 percent (NESCAUM, "Assessment of Control Technology Options for BART-Eligible Sources," March 2005). For new FGD systems installed at large (>750 MW) coal-fired power plants, the presumptive norm is 95 percent reduction of SO_2 emissions (USEPA, Appendix Y to Part 51 – Guidelines for BART Determinations under the Regional Haze Rule).

Dry (or semi-dry) FGD processes are similar in concept to wet FGD processes but do not saturate the flue gas stream with moisture. Dry scrubbers are of two general types: dry sorbent injection and spray dryers. With the former, an alkaline reagent such as hydrated lime or soda ash is injected directly into the flue gas stream to neutralize the acid gases. In spray dryers, the flue gas stream is passed through an absorber tower in which the acid gases are absorbed by an atomized alkaline slurry. The SO_2 removal efficiencies range from 40 to 60 percent for existing dry injection systems and from 60 to 95 percent for existing lime spray dryer systems (NESCAUM, 2005). A PM control device (ESP or fabric filter) is always installed downstream of a dry or semi-dry scrubber to remove the sorbent from the flue gas.

Low-Sulfur Coal

Because SO_2 emissions are directly related to the sulfur content of the fuel burned, reducing the amount of sulfur in the fuel reduces SO_2 emissions. Usually, for operational reasons, a facility cannot make a complete switch from one fuel type to another. Instead, the facility may be able to blend different fuels to obtain a lower-sulfur mix that emits less SO_2 upon combustion – for example, blending low-sulfur bituminous or subbituminous coal with a high-sulfur bituminous coal. The feasibility of fuel switching or blending depends on the physical characteristics of the plant (including boiler type), and significant modifications to systems and equipment may be necessary to accommodate the change in fuels. Switching to a lower-sulfur coal can affect coal handling and preparation systems, ash handling systems, boiler performance, and the effectiveness of PM emission controls. To meet federal acid rain requirements, many facilities have switched to lower-sulfur coals, resulting in SO_2 emission reductions of 50 to 80 percent.

2.3.1 Potential Costs of SO_2 Controls

PSNH Merrimack Station is required by New Hampshire law to install an FGD system to reduce mercury emissions (with SO_2 removal as a co-benefit) at both Unit MK1 (not a BART-eligible unit) and Unit MK2 (a BART-eligible unit). A company estimate for the project placed the capital cost at $457 million, or $1,055/kW (both amounts in 2008$) to install a wet limestone FGD system. Using 2002 baseline emissions of 30,657 tons of SO_2 from Units MK1 and MK2 combined, and a minimum capture efficiency of 90 percent for this pollutant, the annualized capital cost translates to about $1,400 per ton of SO_2 removed.

The project cost is said to be in line with the costs of multiple-unit scrubber installations occurring elsewhere in the country. However, PSNH's estimated cost per kilowatt is at least triple the cost range for FGD systems as reported in MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007 (see Reasonable Progress Report, Attachment Y). The PSNH estimated cost is also more than double the estimate of $300/kW to $500/kW as reported in a 2008 survey of FGD systems (George W. Sharp, "What's That Scrubber Going to Cost?," *Power*, March 1, 2009). The higher cost-per-kW for Unit MK2 may reflect industry-wide increases in raw material, manufacturing, and construction costs but may also reflect site-specific factors such as unit size, type, and difficulty of retrofit.

The costs of switching to lower-sulfur coal at PSNH Merrimack Station would rest on the incremental cost of purchasing the lower-sulfur material at prevailing market prices. Even if a lower-sulfur coal is available at reasonable additional cost, operational considerations related to the physical characteristics of Unit MK2 may dictate the choice of coal for this unit. (Only certain types of coal can be used in wet-bottom, cyclone boilers; and lower-sulfur coals have already been tested and adopted for regular use at this facility.) Commodity spot prices for coal vary considerably. For example, from late March to early May 2009, the price spread between Northern Appalachia coal (<3.0 SO_2) and Central Appalachia coal (1.2 SO_2) ranged from $10 to $25 per ton (source: Energy Information Administration, http://www.eia.doe.gov/fuelcoal.html).

2.3.2 Other Environmental and Energy Impacts of SO_2 Controls

An FGD system typically operates with high pressure drops across the control equipment, requiring increased energy usage for blowers and circulation pumps. Some configurations of FGD systems also require flue gas reheating to prevent operational problems (including physical damage to equipment), resulting in higher fuel usage per unit of net electrical generation. Documentation for EPA's Integrated Planning Model (IPM®) indicates that a wet FGD system reduces the generating capacity of the unit by about 2 percent.

Flue gas desulfurization has impacts on the operation of solid waste and wastewater management systems. In addition to removing SO_2, the FGD process removes mercury and other metals and solids. Often, gypsum produced in a limestone FGD process is recycled or sold to cement manufacturers; otherwise, the sludge must be stabilized and placed in an approved landfill. Gypsum must be dewatered before it can be handled, resulting in a wastewater stream that requires treatment. This wastewater stream increases the sulfates, metals, and solids loadings on the receiving wastewater treatment plant. Sometimes an additional clarifier is required to remove wastewater solids coming from the FGD system.

Wet FGDs increase the amount of water vapor entrained in the flue gas. The result is a lower stack exit temperature and a more visible plume at the stack outlet.

3. DISCUSSION OF CURRENT POLLUTION CONTROL EQUIPMENT AND EMISSIONS

3.1 Discussion of Current NO_X Emissions and Controls

In 1994, PSNH installed an SCR system on Unit MK2, the first such system to be used on a coal-fired, wet-bottom, cyclone boiler in the United States. The SCR was designed to meet NO_X Reasonably Available Control Technology (RACT) limits. Specifically, Unit MK2 is subject to a NO_X RACT Order limit of 15.4 tons per calendar day and a second NO_X RACT Order limit of 29.1 tons per calendar day for combined emissions from Units MK1 and MK2. The facility must also meet a less stringent federal acid rain program limit of 0.86 lb NO_X/MMBtu. PSNH has a monetary incentive to surpass the NO_X RACT requirements because further emission reductions allow the utility to accumulate DERs. Actual NO_X emissions for Unit MK2 were reported as 2,871 tons in baseline year 2002.

Since January 2001, the SCR on Unit MK2 has reduced NO_X emissions to between 0.15 and 0.37 lb/MMBtu (calendar monthly average), with a few excursions outside this range. (Note that the existing NO_X RACT limit of 15.4 tons per calendar day is mathematically equivalent to 0.37 lb/MMBtu.) Data available from the period of 1993 to early 1995, prior to operation of the SCR, provide a baseline for uncontrolled NO_X emissions in the range of 2.0 to 2.5

lb/MMBtu. Taken together, this information indicates that Unit MK2 achieves a control level that exceeds 85 percent most of the time and frequently surpasses 90 percent.

3.2 Discussion of Current PM Emissions and Controls

PSNH Merrimack Station Unit MK2 has two electrostatic precipitators (ESPs), dry type, operating in combination with a fly ash reinjection system. The ESPs have been upgraded with state-of-the-art electronic controls. Installation of the ESPs has reduced PM emissions from this unit by about 99 percent, based on a review of 2002 emissions data. The current air permit for the facility requires that Unit MK2 meet a total suspended particulate (filterable TSP) limit of 0.227 lb/MMBtu and a TSP emissions cap of 3,458.6 tons/year. However, the 0.227 lb/MMBtu rate does not reflect the true capabilities of the ESPs to control particulate emissions. Stack testing on three separate dates in 1999 and 2000 found actual TSP emissions to be 0.043, 0.041, and 0.021 lb/MMBtu after controls. The most recent test, in May 2009, produced an emission rate of 0.032 lb/MMBtu. Total TSP emissions from this unit were 210 tons in 2002.

3.3 Discussion of Current SO_2 Emissions and Controls

New Hampshire law requires PSNH Merrimack Station to install and operate a scrubber system for both Unit MK1 and Unit MK2 by July 1, 2013. While the primary intent of this law is to reduce mercury emissions from the company's coal-fired power plants, a major co-benefit is SO_2 removal. Pursuant to this statutory obligation, New Hampshire issued a permit to PSNH on March 9, 2009, for the construction of a wet, limestone-based FGD system to control mercury and SO_2 emissions at Merrimack Station. The permit requires an SO_2 control level of at least 90 percent for Unit MK2. The specific language of the permit states as follows:

> Beginning on July 1, 2013,…SO_2 emissions shall be controlled to 10 percent of the uncontrolled SO_2 emission rate (90 percent SO_2 removal)…The Owner shall submit a report no later than December 31, 2014 that includes the calendar month average SO_2 emission rates at the inlet and outlet of the FGD and the corresponding calendar month average emissions reductions during the preceding 12 months of operation,…DES will use this data to establish the maximum sustainable rate of SO_2 emissions reductions for MK2. The maximum sustainable rate is the highest rate of reductions that can be achieved 100 percent of the time...This established rate shall be incorporated as a permit condition for MK2. Under no circumstances shall the SO_2 removal efficiency for MK2 be less than 90 percent.

These permit conditions effectively require that actual SO_2 removal efficiencies *exceed* 90 percent on average for Unit MK2. This plant must also meet general regulations for coal-burning devices that limit the sulfur content of the coal to 2.0 pounds per million BTU gross heat content averaged over any consecutive 3-month period, and 2.8 pounds per million BTU gross heat content at any time. Since 2002, the facility has operated well within these fuel limits. More specifically, PSNH has worked to control coal sulfur content to reduce SO_2 emissions and minimize the purchase of SO_2 allowances. Because the particular boiler design does not permit the burning of straight low-sulfur coal, the company blends coals to bring average sulfur content to a level that is consistent with sustainable boiler operations.

PSNH must also meet a fleet-wide SO_2 emissions cap of 55,150 tons/year effective for all electrical generating units at its Merrimack, Newington, and Schiller Stations. In 2002, actual SO_2 emissions from Unit MK2 were 20,902 tons.

4. REMAINING USEFUL LIFE OF UNIT

Where a reasonable control option is available for a BART-eligible unit, the unit should be controlled in a manner consistent with BART and the expected useful life of the unit. Originally, electric generating units were estimated to have a life expectancy of 30 to 40 years, but many units are lasting 50 years or more. In many cases, it is less expensive to keep existing units operating than to build replacement facilities and/or new transmission lines. Merrimack Station Unit MK2 was built in 1968. PSNH's commitment to install new emission controls on this unit demonstrates the company's belief that this unit is capable of supplying electricity to the region for many years beyond the present.

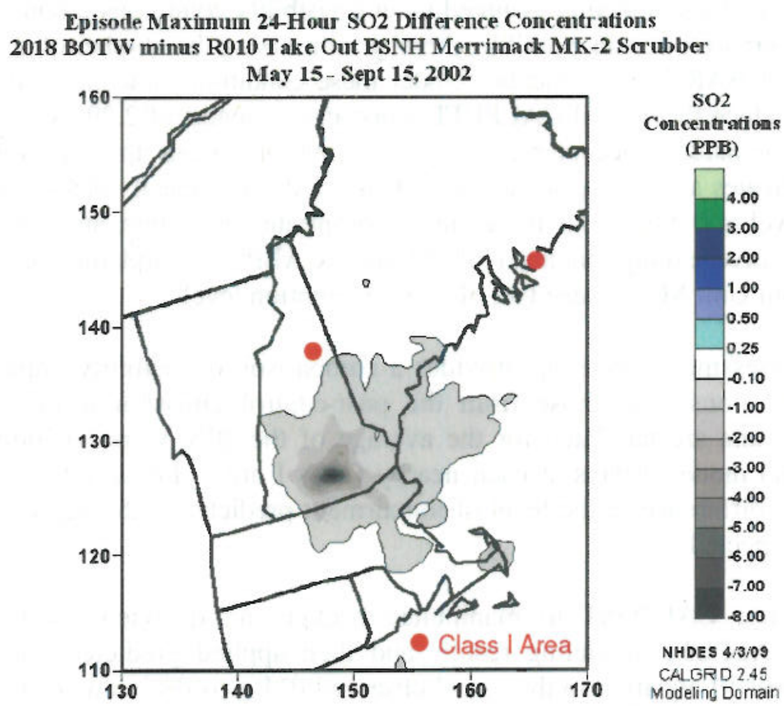
5. DEGREE OF VISIBILITY IMPROVEMENT ANTICIPATED FROM BART

The New Hampshire Department of Environmental Services (NHDES) conducted a screening-level analysis of the anticipated visibility effects of BART controls at PSNH Merrimack Station Unit MK2. Specifically, one modeling run using the CALGRID photochemical air quality model was performed to assess the effects of installing an FGD system on Unit MK2. The simulation covered the full summer modeling episode (from May 15 to September 15, 2002) with MANE-VU's 2018 beyond-on-the-way (BOTW) emissions inventory scenario as a baseline. The BOTW emissions scenario reflects controls from potential new regulations that may be necessary to attain National Ambient Air Quality Standards and other regional air quality goals, beyond those regulations that are already "on the books" or "on the way."

The CALGRID model outputs took the form of ambient concentration reductions for SO_2, $PM_{2.5}$, and other haze-related pollutants within the region. NHDES post-processed the modeled concentration reductions to estimate the corresponding visibility improvements at Class I areas such as Acadia National Park, Moosehorn National Wildlife Refuge, and Lye Brook Wilderness Area (i.e., concentration impacts were converted to visibility impacts). Visibility can be quantified using deciviews (dv), a logarithmic unit of measure to describe increments of visibility change that are just perceptible to the human eye.

Based on the modeling results, the installation of scrubber technology with 90-percent removal efficiency on Unit MK2 is expected to reduce maximum predicted 24-hour average SO_2 concentration impacts by up to 21 $\mu g/m^3$ (8 ppb by volume; see Figure 5-1) and maximum predicted 24-hour average $PM_{2.5}$ concentration impacts by up to 1 $\mu g/m^3$. The largest modeled pollutant concentration reductions occur within a 50-kilometer radius of the facility. For the affected Class I areas (located 100 to 500 kilometers away), reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, are expected to yield a nominal improvement in visibility (about 0.1 deciview) on direct-impact hazy days.

Figure 5-1



NHDES's reliance on CALGRID differs somewhat from EPA's preferred methodology. CALPUFF is EPA's preferred model for performing long-range visibility assessments of individual sources to distant Class I areas, in part because it is considered to be a conservative model or one that is capable of estimating worst-case impacts rather than expected impacts. This makes CALPUFF ideally suited to screening BART sources for exemption purposes because it is likely to identify virtually all sources that could provide visibility benefits when their emissions are controlled.

CALGRID is a sister program to CALPUFF and shares much of the same chemistry; however, it works as a gridded model rather than a puff tracking model, and it has the advantage of easily tracking 20% worst visibility days and cumulative impacts by modeling all source sectors. NHDES chose to use CALGRID since it is much easier to track the dynamics of impacts from single sources to multiple Class I areas on targeted days, rather than just applying the maximum impact conditions that may or may not be associated with 20% worst days. While the CALPUFF model's CALPOST post-processor has an option for application on 20% best visibility days, it does not in fact isolate those 20% best days for analysis. It simply changes the background values the model uses to adjust what it estimates to be appropriate background levels. It does not account for wind directions that may be preferentially included or excluded on such days.

Nevertheless, to provide a comparison with New Hampshire's CALGRID modeling results, NHDES conducted a limited set of CALPUFF runs for the New Hampshire BART-eligible sources under controlled and uncontrolled conditions. Before considering the findings of this supplemental modeling work, it is useful to review the results of the BART eligibility modeling performed by MANE-VU.

In previous modeling, MANE-VU used CALPUFF to assist in the identification of BART-eligible sources. This modeling assumed natural visibility conditions (about 7 dv) to produce the most conservative results possible, thereby minimizing the number of sources that would "model out" of BART requirements. Under these conditions, uncontrolled emissions from Unit MK2 produce theoretical CALPUFF worst-case impacts of 2.29 dv at Acadia National Park. EPA considers acceptable source exemptions when this form of conservative modeling indicates a source produces less than 0.5 dv of impact. MANE-VU considers an exemption level of 0.2 to 0.3 dv to be more appropriate but prefers, and has applied, an even more conservative exemption level of 0.1 dv. CALPUFF modeling results for baseline emissions from Unit MK2 exceed all of these exemption levels.

The BART assessment modeling provides a comparison of visibility impacts from current allowable emissions with those from the post-control emission level (or levels) being assessed. Results are tabulated for the average of the 20% worst visibility (in this case, about 22.8 dv) modeled days at each nearby Class I area. For any pair of control levels evaluated, the difference in the level of impairment predicted is the degree of improvement in visibility expected.

Rather than use CALPOST to manipulate background deciview calculations, NHDES normalized CALPUFF modeling results and then applied predicted concentrations to a logarithmic best-fit equation to the actual observed $PM_{2.5}$-to-deciview relationship measured at Acadia NP, Great Gulf NW, and Lye Brook NW. Thus, CALPUFF was applied in a relative way using real observed data as the basis. At this point, a number of background visibility scenarios could be calculated from the resulting PM-mass-to-deciview equation. In accordance with BART guidance, the natural visibility condition (about 7 dv) was used for exemption purposes, and 20% worst visibility (22.8 dv) was used for assessment of BART control effectiveness. The CALPUFF-predicted visibility benefits from BART controls on 20% worst visibility days are as follows:

Table 5-1. CALPUFF Modeling Results for Merrimack Station Unit MK2: Visibility Improvements from BART Controls on the 20% Worst Visibility Days

Pollutant	Control Technology	Control Level	Visibility Improvement (dv)		
			Acadia NP	Great Gulf NW	Lye Brook NW
SO_2	FGD	90%	0.28	0.22	0.03
NO_X	SCR Upgrade	89%	0.01	0.01	< 0.01*
PM	ESP Upgrade	99.4%	<0.01*	<0.01*	< 0.01*
	Baghouse	99%	-0.02	-0.02	-0.01

* below sensitivity limit of model

While Unit MK2 was predicted to have up to 2.29 dv impact at Acadia National Park under natural conditions, the basis of the BART assessment evaluation changes to 20% worst visibility days. On those days, a 90% reduction in sulfur emissions at Unit MK2 results in only a 0.28 dv visibility improvement. At first these results may appear to be incorrect; however, on further examination, it is found that CALPUFF predicts the same amount of sulfate from Unit MK2 reaching Acadia under both best and worst visibility conditions. The difference is that there is greater than an order of magnitude more sulfate coming from other sources on the 20% worst visibility days, raising the background concentrations to much higher levels. Because the deciview scale is logarithmic, the same mass reduction of 0.26 $\mu g/m^3$ of sulfate from this one source results in wide differences in deciview impacts for different background visibility conditions at opposite ends of the range.

The above analysis indicates that CALPUFF and CALGRID have aligned better in their predictions than might be expected. This result may be attributed to the similar chemistry used in both models and to the specific circumstances of this case in which the prevailing wind direction on the 20% worst visibility days carries Unit MK2 emissions directly toward Acadia National Park. The big discrepancy occurs under best visibility days, when CALGRID (correctly) does not align the source to receptor, but CALPUFF (incorrectly) applies wind directions for worst visibility days to the best day calculations.

6. DETERMINATION OF BART

Based on the completed review and evaluation of existing and potential control measures for PSNH Merrimack Station Unit MK2, it is determined that the NO_X, PM, and SO_2 controls described below represent Best Available Retrofit Technology for this unit.

6.1 Selecting a Pollution Control Plan for NO_X

PSNH currently operates an SCR system on Unit MK2. This system was installed in 1994 to meet the requirements of NO_X RACT and the ozone season NO_X budget program. SNCR is the only other control technology available for controlling NO_X emissions from this unit. SCR yields higher NO_X removal rates and is more cost-effective than SNCR. For units that already have seasonally operated SCRs, year-round operation is EPA's presumptive norm for BART. PSNH estimated, in 1998, that the existing SCR system could be operated year-round at a cost of $494 per ton of NO_X removed.

For an early-generation SCR that has received previous retrofits to improve its performance, further upgrades to this NO_X control system appear to be impractical and would yield negligible (generally less than 0.01 dv) improvement in visibility. Additional upgrades would require major redesign and construction at a location where physical space is already constrained. Capital costs would be comparable to installing a new SCR and would achieve only marginal additional reductions in NO_X emissions. Because Unit MK2 has an existing SCR system designed to meet other air program requirements that could be operated year-round at reasonable cost, full-time operation of the existing SCR is considered to be BART for NO_X control on this unit.

EPA has provided presumptive BART emission rates that are broadly applicable to power plants larger than 750 MW but are not necessarily representative of smaller EGUs like Unit MK2. In the case of Unit MK2, the cyclone boiler has a relatively high uncontrolled NO_X emission rate ($\geq$2.0 lb/MMBtu); so it follows that the controlled emission rate, even at 90 percent control efficiency, would be above the presumptive norm of 0.10 lb/MMBtu applicable to larger EGUs of its type. The past decade of emissions records for Unit MK2 shows monthly average NO_X emission rates normally ranging between 50 and 100 percent of the RACT limit. The existing NO_X RACT limit of 15.4 ton/day, equivalent to of 0.37

lb/MMBtu[1], corresponds to a NO_X control rate of approximately 85 percent.

PSNH has documented operational and infrastructural changes that would be needed in order to allow the company to guarantee a NO_X performance level lower than the current effective limit of 0.37 lb/MMBtu. This might be accomplished by increasing the frequency of maintenance cleanings and accelerating the rate of catalyst replacement. The three major cost components would be: 1) the direct costs of additional cleanings, 2) the costs of purchased replacement power during scheduled outages for the additional cleanings, and 3) the costs of extra catalyst. Depending on the particular scenarios and assumptions applied, the estimated costs of reducing the NO_X limit to 0.34 lb/MMBtu (a reduction of 0.03 lb/MMBtu) would fall between \$3,000 and \$10,000 per ton of NO_X removed, which is generally above the cost-effective range. NHDES therefore finds that the current NO_X RACT limit, expressed as 0.37 lb/MMBtu, reasonably represents the sustainable performance capabilities of this unit and is also appropriate as a BART control level for NO_X on a 30-day averaging basis.

6.2 Selecting a Pollution Control Plan for PM

PSNH currently operates two ESPs in series on Unit MK2. Mechanical collectors (cyclones) are effective only for coarse particle removal and would be impractical as a retrofit for Unit MK2, where the more efficient ESPs already exist. Fabric filters have performance levels comparable to ESPs and are a suitable PM control technology for power plant emissions. However, fabric filters are also impractical as a retrofit for Unit MK2 under present circumstances: ESPs already exist, physical space at the facility is limited, and the addition of an FGD system is now in progress.

The existing ESPs were previously upgraded to include state-of-the-art electronic controls. Further upgrading would require either major equipment substitutions or the addition of a third ESP in series with the two existing units. Adding a third ESP might be physically impossible because of the aforementioned spatial limitations following past improvements to emission control systems. To undertake either major equipment replacement or installation of a third ESP, if it could be done at all, would require a major capital expenditure. Typical equipment replacement costs for ESP upgrades may be in the range of \$10,000 to \$30,000 per MW. For Unit MK2, additional costs of this magnitude are not easily justified when weighed against the visibility improvement (less than 0.01 dv on the 20 percent worst visibility days) that would be realized.

The current PM emission limit for Unit MK2 is not reflective of the performance capabilities of the existing ESPs. However, the volume of available stack test data is insufficient to establish a conclusive, long-term BART performance level of 0.04 lb/MMBtu or lower for this unit. NHDES has developed a draft rule that will hold TSP emissions to a maximum of 0.08 lb/MMBtu but will apply this limitation more broadly than BART requires. The new PM emission limit will affect both of Merrimack Station's coal-fired utility boilers – Unit MK1 (not a BART-eligible facility) and Unit MK2 – as explained below.

[1] The 0.37 lb/MMBtu NO_X emission rate for MK2 is calculated from its maximum heat input rate of 3,473 MMBtu/hr and the applicable NO_X RACT limit of 15.4 tons per day, as follows:
[(15.4 tons/day × 1 day/24 hr) × 2,000 lb/ton] ÷ 3,473 MMBtu/hr = 0.37 lb/MMBtu

In the proposed rule, Units MK1 and MK2 are placed within a regulatory "bubble" for the purposes of TSP compliance. This arrangement serves both necessity and convenience because the two units will share a common stack. The following procedure was used to calculate the maximum allowable emission rate for the combined source:

1. For BART-eligible Unit MK2, the maximum heat input rating of 3,473 MMBtu/hr was multiplied by MANE-VU's lowest presumptive control level for TSP emissions, 0.02 lb/MMBtu, to obtain an emission rate of 69.46 lb/hr.
2. For non-BART Unit MK1, the maximum heat input rating of 1,238 MMBtu/hr was multiplied by the unit's permitted TSP limit, 0.27 lb/MMBtu, to determine an emission rate of 334.26 lb/hr.
3. The individual emission rates were summed to yield a total maximum emission rate of 403.72 lb/hr. This value was divided by the total maximum heat input rate, 4,711 MMBtu/hr, to obtain the new TSP emission limitation of 0.08 lb/MMBtu (rounded down from 0.086 lb/MMBtu).

By including Unit MK1 in the rule, the allowable TSP emissions from the two coal-fired units combined will be less than the allowable emissions would be if the limit for Unit MK1 remained separate and unchanged, and the limit for Unit MK2 were reduced to 0.04 lb/MMBtu, its approximate performance capability from actual stack test data.[2]

It is concluded that the existing ESPs, operating in conjunction with the FGD process, will provide the most cost-effective controls for particulate emissions. Continued operation of the existing ESPs, controlled to emission rates not exceeding the new emission limit described above, represents BART for PM control on Unit MK2.

6.3 Selecting a Pollution Control Plan for SO_2

PSNH Merrimack Station is installing a flue gas desulfurization system to remove mercury emissions in compliance with New Hampshire law. As a co-benefit, the FGD system is expected to remove more than 90 percent of SO_2 emissions. Because this installation is already mandated and because it will attain SO_2 removal rates approaching the BART presumptive norm of 95 percent (generally applicable to facilities larger than Merrimack Station), the FGD system is considered to be BART for SO_2 control on Unit MK2. (Note that, at an installed cost exceeding \$1,000/kW, the FGD system being added to this facility is more expensive than the industry average and might not be viewed as cost-effective if its only purpose were to satisfy BART requirements.)

[2] For the bubble concept, the combined emission rate = 0.08 lb/MMBtu × 4,711MMBtu/hr = <u>377 lb/hr</u>. For the stand-alone alternative, the sum of the individual emission rates = (0.04 lb/MMBtu × 3,473 MMBtu/hr) + (0.27 lb/MMBtu × 1,238 MMBtu/hr) = <u>473 lb/hr</u>.

7. SUMMARY AND CONCLUSIONS

Table 7-1 summarizes best available retrofit technology for PSNH Merrimack Station Unit MK2 for the pollutants NO_X, PM, and SO_2. The summary includes existing controls that have been determined to meet or exceed BART requirements as well as changes in progress that are consistent with BART requirements. NHDES has already issued a temporary permit (construction permit) for the installation of the flue gas desulfurization system and is not requesting further action of Merrimack Station at this time in order to comply with BART.

Table 7-1. Summary of BART Determinations for Unit MK2

Pollutant	Current Emission Controls	Additional Emission Controls in Progress	BART
NO_X	SCR	None	SCR
PM	Two ESPs in series	None	Two ESPs in series
SO_2	Fuel sulfur limits set at 2.0 lb sulfur/MMBtu (averaged over 3 mos.) and 2.8 lb sulfur/MMBtu at any time	Flue gas desulfurization (FGD), with required SO_2 percent reduction set at maximum sustainable rate, but not less than 90% on a calendar monthly average basis	Flue gas desulfurization (FGD), with required SO_2 percent reduction set at maximum sustainable rate, but not less than 90% on a calendar monthly average basis; existing fuel sulfur limits to remain in effect

NEW HAMPSHIRE BART ANALYSIS: Merrimack Station Unit MK2 (320 MW)

Pollutant	Emission Control Technology	Control Level	Uncontrolled Emissions ton/yr	Controlled Emissions ton/yr	Emission Reductions ton/yr	Estimated Cost of Emission Controls[7]	Capital $	Capital $/kW	O&M $/yr	Total Annual $/yr	Average $/ton	Ref.
NO_X	SCR (existing)	85%	19,140 [1]	2,871 [2]	16,269		37,710,186	118	1,910,432	5,069,414	312	8
	SNCR	45%	19,140 [1]	10,527	8,613		3,876,771	12	4,781,136	5,105,893	593	8
PM	2 ESPs (existing)	99+%	30,060 [2]	210 [2]	29,850	min.	23,280,363	73	1,086,417	2,571,006	86	9
						max.	62,080,967	194	1,940,030	7,140,553	239	
	Fabric Filters	99%	30,060 [2]	301	29,759	min.	18,624,290	58	2,172,834	3,732,991	125	9
						max.	62,080,967	194	3,104,048	8,304,571	279	
SO_2	Lower-S coal (existing)	40% [3]	—	—	—		—	—	—	—	—	
	FGD	90% [4]	20,902 [5]	2,090	18,812 [6]		457,000,000	1,055	unknown	unknown	unknown	10

1 Estimated.

2 2002 (baseline) emissions as taken from NHDES data summary derived from facility's annual emissions statement.

3 Estimated average reduction in fuel sulfur content with use of lower-S coal, resulting in equivalent reduction in SO_2 emissions.

4 Additional control level on emissions after existing controls have been applied; overall control level with use of lower-S coal is estimated to be 40 + 90(1 - 0.40) = 94%

5 2002 (baseline) emissions with use of lower-sulfur coal at ~1.0 % S by weight.

6 Reductions from baseline emissions.

7 All cost estimates adjusted to 2008$.

8 USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

9 NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

10 FGD capital cost is PSNH's estimate (2008$) for Units MK1 (113 MW) and MK2 (320 MW) combined.

Merrimack Station Unit MK2: NO_X Controls

Plant type	wet-bottom, cyclone, coal-fired boiler	
Generation capacity	320	MW
Maximum heat Input	3,473	MMBtu/hr
Capacity factor	80	%
Annual hours	8,760	hr/yr
Annual production	2,242,560,000	kWh/yr

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	7,180	6,703	7,462	7,280	7,577	7,477	6,519
Total Heat Input*	22,013,513	22,006,524	24,024,382	23,795,575	25,328,218	25,448,437	18,282,000
Capacity factor**	72.4%	72.3%	79.0%	78.2%	83.3%	83.6%	60.1%

*MMBtu (from CEM data)

**Based on ratio of total heat input to theoretical maximum heat input

Costs: 2004$

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M	Scaled Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
SCR	111.48	103.46	33,108,152	2,773,470	0.74	0.69	219,771	0.67	0.65	1,457,518	1,677,289	4,450,759	16,269	274
SNCR	11.04	10.64	3,403,662	285,125	0.16	0.15	49,328	1.46	1.85	4,148,332	4,197,661	4,482,786	8,613	520

Costs: 2008$ 2004$ → 2008$ 1.139 multiplier

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M	Scaled Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
SCR	126.98	117.84	37,710,186	3,158,982	0.84	0.78	250,319	0.76	0.74	1,660,113	1,910,432	5,069,414	16,269	312
SNCR	12.57	12.11	3,876,771	324,757	0.18	0.18	56,185	1.66	2.11	4,724,951	4,781,136	5,105,893	8,613	593

Cost Reference:

USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Merrimack Station Unit MK2: PM Controls

Plant type	wet-bottom, cyclone, coal-fired boiler	
Capacity	320	MW
Maximum heat Input	3,473	MMBtu/hr
Capacity factor	80	%
Annual hours	8,760	hr/yr
Annual production	2,242,560,000	kWh/yr
Flue gas flow rate	1,362,620	acfm

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	7,180	6,703	7,462	7,280	7,577	7,477	6,519
Total Heat Input*	22,013,513	22,006,524	24,024,382	23,795,575	25,328,218	25,448,437	18,282,000
Capacity factor**	72.4%	72.3%	79.0%	78.2%	83.3%	83.6%	60.1%

*MMBtu (from CEM data)

**Based on ratio of total heat input to theoretical maximum heat input

Costs: 2004$

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	15.00	20,439,300	1,712,200	0.25	0.45	953,834	2,666,034	29,850	89
	max.	40.00	54,504,800	4,565,867	0.65	0.60	1,703,275	6,269,142	29,850	210
Wet ESP	min.	15.00	20,439,300	1,712,200	0.15	0.25	545,048	2,257,248	29,850	76
	max.	40.00	54,504,800	4,565,867	0.50	0.50	1,362,620	5,928,487	29,850	199
Fabric Filter - Reverse Air	min.	17.00	23,164,540	1,940,494	0.35	0.70	1,430,751	3,371,245	29,759	113
	max.	40.00	54,504,800	4,565,867	0.75	0.80	2,112,061	6,677,928	29,759	224
Fabric Filter - Pulse Jet	min.	12.00	16,351,440	1,369,760	0.50	0.90	1,907,668	3,277,428	29,759	110
	max.	40.00	54,504,800	4,565,867	0.90	1.10	2,725,240	7,291,107	29,759	245

Cost Reference:

NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Costs: 2008$ 2004$ → 2008$ 1.139 multiplier

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	17.09	23,280,363	1,950,196	0.28	0.51	1,086,417	3,036,613	29,850	102
	max.	45.56	62,080,967	5,200,523	0.74	0.68	1,940,030	7,140,553	29,850	239
Wet ESP	min.	17.09	23,280,363	1,950,196	0.17	0.28	620,810	2,571,006	29,850	86
	max.	45.56	62,080,967	5,200,523	0.57	0.57	1,552,024	6,752,547	29,850	226
Fabric Filter - Reverse Air	min.	19.36	26,384,411	2,210,222	0.40	0.80	1,629,625	3,839,848	29,759	129
	max.	45.56	62,080,967	5,200,523	0.85	0.91	2,405,637	7,606,160	29,759	256
Fabric Filter - Pulse Jet	min.	13.67	18,624,290	1,560,157	0.57	1.03	2,172,834	3,732,991	29,759	125
	max.	45.56	62,080,967	5,200,523	1.03	1.25	3,104,048	8,304,571	29,759	279

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