United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
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N3615 (2350)

Robert R. Scott, Director
Air Resources Division
New Hampshire Department of Environmental Services
P.O. Box 95
29 Hazen Drive
Concord, New Hampshire 03302-0095

Dear Mr. Scott:

Enclosed are our comments on the Best Available Retrofit Technology (BART) determinations proposed by the New Hampshire Department of Environmental Services (NHDES) for Public Service New Hampshire's (PSNH) Merrimack Station Unit MK2 and Newington Station Unit NT1. These comments supplement the Septemgber 26, 2008, comments that we submitted on the draft NHDES visibility protection plan. We commend NHDES for its proposals that would lead to significant reductions in sulfur dioxide emissions from both units. We note that, even though those reductions may be the result of other programs in the state, they are also required under the BART provisions of the Regional Haze regulations. We request that emission limits be established, as required by EPA's BART Guidelines, to ensure that the emission control technologies proposed by NHDES as BART are operated to the fullest reasonable extent of their capabilities. We also ask that NHDES provide further documentation in support of its BART determinations.

Again, we appreciate the opportunity to work closely with the State of New Hampshire and compliment you on your hard work and dedication to significant improvement in our nation's air quality values and visibility. For further information, please contact Holly Salazer (NPS Northeast Region) at (814) 865-3100, or Don Shepherd of the NPS Air Resources Division at (don_shepherd@nps.gov, 303-969-2075).

Sincerely,

Bruce Polkowsky for/

John Bunyak
Chief, Policy, Planning and Permit Review Branch

Enclosures

cc:

Stephen Perkins (Suite 1100 CAA)
Director, Office of Ecosystem Protection
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BART Review Comments
National Park Service (NPS)
Public Service New Hampshire (PSNH) Merrimack Station

PSNH Merrimack Station has two coal-fired steam-generating boilers that operate nearly full time to meet baseload electric demand. Unit MK2, the only BART-eligible unit, 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 (SCR) to remove oxides of nitrogen (NO_X) formed during the combustion process. Two electrostatic precipitators (ESPs) operate in series to capture particulate matter (PM). Also, construction has begun on a scrubber system that will reduce sulfur dioxide (SO_2) emissions. According to EPA's Clean Air Markets (CAM) database, in 2007, emissions from Unit #2 were: 25,064 tpy SO_2 (@ 1.97 lb/mmBtu) and 2,248 tpy NO_X (@ 0.19 lb/mmBtu).

Retrofit options for this unit are limited because the facility already has controls in place for NO_X and PM, and only a few emission control technologies are compatible with the type of boiler design employed.

BART Analysis for SO_2

STEP 1 – Identify all available retrofit emissions control techniques
New Hampshire Department of Environmental Services (NHDES): SO_2 control technologies available and potentially applicable to Unit MK2 are wet flue gas desulfurization (FGD) and use of low-sulfur coal.
NPS: PSNH has proposed wet FGD which potentially provides the highest level of reduction.

STEP 2 – Eliminate technically infeasible options
NPS: No SO_2 control options were eliminated on this basis.

STEP 3 – Evaluate control effectiveness of remaining control options
NHDES: SO_2 removal efficiencies for existing wet limestone scrubbers range from 31 to 97 percent, with an average of 78 percent (NESCAUM, 2005).
NPS: NHDES should include requirements that PSNH optimize operation of the wet FGD.

STEP 4 – Impact analysis
NHDES: 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 equates to about $1,400 per ton of SO_2 removed.
NPS: The estimated cost is within the range of reasonable costs suggested by EPA.

STEP 5 – Determine visibility impacts
see below

Determination of BART for SO_2

NHDES: New Hampshire law requires PSNH Merrimack Station to install and operate a scrubber system for both MK1 and 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. Because this installation is already mandated and because it will attain SO_2 removal rates approaching the BART presumptive norm of 95 percent (applicable to EGUs substantially larger than Merrimack Station), the FGD system is considered to be BART for SO_2 on Unit MK2. NHDES is not requesting further action of Merrimack station at this time in order to comply with BART.

NPS: NHDES should include requirements that PSNH optimize operation of the wet FGD.

<u>BART Analysis for NO_x</u>

STEP 1 – Identify all available retrofit emissions control techniques

NHDES: The only NO_X control technology options available and potentially applicable to Unit MK2 are selective non-catalytic reduction (SNCR) and SCR.

NPS: PSNH has proposed SCR which potentially provides the highest level of reduction.

STEP 2 – Eliminate technically infeasible options

NPS: No NO_X control options were eliminated on this basis.

STEP 3 – Evaluate control effectiveness of remaining control options

NHDES: NO_X emission reductions of about 75 to 90 percent have been obtained with SCR on coal-fired boilers in the U.S. 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 U.S. Designed to meet NO_X Reasonably Available Control Technology (RACT) limits, the SCR has reduced NO_X emissions by 85 to 92 percent. Unit MK2 is also required to meet a federal acid rain limit of 0.86 lb NO_x /mmBtu, an additional NO_X RACT Order limit of 15.4 tons per calendar day, and a NO_x RACT Order limit of 29.1 tons per calendar day for Units MK1 and MK2 combined. PSNH is allowed to meet the 15.4 ton-per-day limit for Unit MK2 by using ozone-season discrete emission reductions (DERs). In 2002, actual NO_X emissions for Unit MK2 were reported as 2,871 tons.

NPS: NHDES should explain why the SCR (with or without addition of combustion controls) cannot achieve better than the estimated 85 percent control. NHDES should include requirements that PSNH optimize operation of the SCR.

STEP 4 – Impact analysis

NHDES: 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 current (but more generic) estimates presented in Table 2-1.
NPS: The estimated cost is within the range of reasonable costs suggested by EPA.

STEP 5 – Determine visibility impacts
see below

Determination of BART for NO_x
NHDES: Because Unit MK2 already has SCR controls in place, the listed costs serve for comparative purposes only. The estimated costs of NO_X emission controls for SNCR and SCR at Merrimack Station Unit MK2 are presented in Table 2-1 of the BART report. 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 EGU the size of Unit MK2. Because the SCR system is already in place to meet other air program requirements and can be operated year-round at reasonable cost, full-time operation of the existing SCR is considered to be BART for NO_X control on Unit MK2.
NPS: Because the only federally-enforceable NO_x limit (described above) does not reflect the full capability of SCR and is well above the presumptive 0.10 lb/mmBtu BART limit for a cyclone furnace, NHDES should include limits that reflect the full capability of the NO_x reduction system.

<u>BART Analysis for PM</u>

STEP 1 – Identify all available retrofit emissions control techniques
NHDES: The only PM control technologies available and potentially applicable to Unit MK2 are electrostatic precipitators, fabric filters, mechanical collectors, and particle scrubbers.
NPS: NHDES should have considered simple, inexpensive upgrades for the ESPs to achieve greater control.

STEP 2 – Eliminate technically infeasible options
NPS: No PM control options were eliminated on this basis.

STEP 3 – Evaluate control effectiveness of remaining control options
NHDES: PSNH Merrimack Station Unit MK2 has two electrostatic precipitators (ESPs), dry type, operating in combination with a fly ash reinjection system. 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. Actual TSP emissions from this unit were 210 tons in 2002.

NPS: A properly designed and operated ESP should be able to achieve 0.015 lb filterable PM/mmBtu. In fact, the data presented by NHDES indicates that the ESPs achieved 0.019 lb TSP/mmBtu in 2002 based upon CAM data heat input of 22,013,515 mmBtu in 2002.

STEP 4 – Impact analysis

NHDES: Because Unit MK2 already has two dry ESPs installed and operating, the tabulated costs are useful for comparative purposes only. 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. 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.

NPS: NHDES conducted no analysis of the cost of upgrading the ESPs.

Determination of BART for PM

NHDES: ESPs already exist, physical space at the facility is limited, and the addition of an FGD system is now in progress. The existing ESPs, operating in conjunction with the FGD process, will provide the most cost-effective controls for particulate emissions. Therefore, continued operation of the existing ESPs is considered to be BART for PM control on Unit MK2.

NPS: Although the existing ESPs may well represent BART, NHDES should evaluate possible upgrades, or, at least, establish a federally-enforceable permit limit that reflects the actual capabilities of the units.

STEP 5 – Determine visibility impacts

NHDES: The 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 CALGRID model outputs took the form of ambient concentration reductions for SO_2, $PM_{2.5}$, and other haze-related pollutant 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). 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.

NPS: EPA recommends use of CALPUFF for modeling single sources in situations like this. CALGRID is more appropriate for multi-source regional modeling and under-predicts impacts relative to CALPUFF. It is likely that, had NHDES applied CALPUFF, it would have produced results that predict significantly higher estimates of visibility benefits that would result from the proposed emission controls.

BART Review Comments
National Park Service (NPS)
Public Service New Hampshire (PSNH) Newington Station Unit NT1

Unit NT1 is the sole electrical generating unit at PSNH Newington Station. It operates at irregular times, principally during periods of peak electric demand. Power is derived from an oil- and/or natural-gas-fired steam-generating boiler with a heat input rating of 4,350 mmBtu/hr and an electrical output of 400 MW. Installed in 1968, the boiler is equipped with Low-NO_X burners, an overfire air system, and water injection to minimize the formation of oxides of nitrogen (NO_X) during the combustion process. The facility also has an electrostatic precipitator to capture particulate matter (PM) in the flue gases. Partial control of SO_2 emissions is provided by sulfur content limits on the fuel oil. According to EPA's Clean Air Markets (CAM) database, in 2002, which were the basis of the New Hampshire Department of Environmental Services (NHDES) BART analysis, emissions from Unit #1 were: 5,226 tpy SO_2 (@ 1.08 lb/mmBtu) and 943 tpy NO_X (@ 0.18 lb/mmBtu).[1]

BART Analysis for SO_2

STEP 1 – Identify all available retrofit emissions control techniques
NHDES: SO_2 control technologies available and potentially applicable to Unit NT1 are wet flue gas desulfurization (FGD) and use of low-sulfur oil.
NPS: NHDES identified a reasonable suite of options.

STEP 2 – Eliminate technically infeasible options
NPS: No SO_2 control options were eliminated on this basis.

STEP 3 – Evaluate control effectiveness of remaining control options
NHDES: SO_2 removal efficiencies for existing wet limestone scrubbers range from 31 to 97 percent, with an average of 78 percent (NESCAUM, 2005).
NPS: NHDES should explain what control efficiency is assumed for the hypothetical new scrubber.

STEP 4 – Impact analysis
NHDES: Despite expressing concern about the high cost estimates,[2] NHDES used the latest Merrimack Station estimate of $1,055/kW for scaling purposes to estimate that the total capital cost of a wet limestone FGD system for Newington Station Unit NT1 would be roughly $422,000,000. NHDES states that "Much caution is necessary in relating this number to the Newington facility: Note that the cost of FGD on oil-fired boilers previously has been estimated to be about *twice* the cost of FGD on coal-fired boilers of

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[1] According to the CAM database, in 2007, emissions from Unit #1 were: 2,269 tpy SO_2 (@ 1.05 lb/mmBtu) and 415 tpy NO_X (@ 0.16 lb/mmBtu).
[2] 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 recent 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).

comparable size (NESCAUM, 2005)." NHDES did not estimate annual costs or cost-effectiveness for this option.

According to NHDES, "The costs of fuel switching at Unit NT1 would depend on the incremental costs of purchasing the lower-sulfur fuel at prevailing market prices. The long-term price differential between 1.0%-sulfur (low-S) residual fuel oil and 2.0%-sulfur residual fuel oil is estimated to be about 7.5 cents/gallon. The differential between 0.5%-sulfur (ultra-low-S) residual fuel oil and 2.0%-sulfur residual fuel oil is estimated to be about twice this amount, or 15 cents/gallon (both estimates in 2008$ based on Energy Information Agency compiled price data for the period 1983-2008.) Using these unit prices, the total cost of switching to low-S residual fuel oil is approximately \$3.3 million per year, or \$1,900 per ton of SO_2 emissions removed; and the cost of switching to ultra-low-S residual fuel oil is approximately \$6.6 million per year, or also \$1,900 per ton of SO_2 emissions removed (both estimates based on 2002 actual fuel oil usage; note that fuel oil usage in 2006-2008 has been below 2002 levels). These results imply that the cost of fuel switching may be relatively constant on a \$/ton basis as long as supplies are adequate...Switching to lower-sulfur fuel oil generally reduces boiler maintenance requirements because less particulate matter is emitted. With fewer material deposits occurring on internal boiler surfaces, the intervals between cleanings/outages can be longer. Also, because lower-sulfur oil reduces the formation of sulfuric acid emissions, corrosion is reduced and equipment life is extended."

STEP 5 – Determine visibility impacts
NHDES: The NHDES conducted a screening level analysis of the anticipated visibility effects of BART controls at PSNH Newington Station Unit NT1. Specifically, one modeling run using the CALGRID photochemical air quality model was performed to assess the effects of installing an FGD system on Unit NT1. The CALGRID model outputs took the form of ambient concentration reductions for SO_2, $PM_{2.5}$, and other haze-related pollutant 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). For the affected Class I areas, reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, are expected to yield a negligible improvement in visibility, according to NHDES.

NPS: EPA recommends use of CALPUFF for modeling single sources in situations like this. CALGRID is more appropriate for multi-source regional modeling and under-predicts impacts relative to CALPUFF. It is likely that, had NHDES applied CALPUFF, it would have produced results that predict significantly higher estimates of visibility benefits that would result from the proposed emission controls.

Determination of BART for SO_2
NHDES: Flue gas desulfurization is a potential SO_2 control option for PSNH Newington Station Unit NT1. However, the cost per ton for FGD on oil-fired boilers is estimated to be about twice the cost of this technology on coal-fired boilers and could be well in

excess of \$1,000/kW for Newington Station. Given the high costs of this option, it is apparent that FGD would be uneconomical as a retrofit for a peak-demand plant the size of Unit NT1.

Use of a lower-sulfur fuel is a practical option for controlling SO_2 emissions at Newington Station. When natural gas is available at reasonable cost relative to residual fuel oil, natural gas is the preferred fuel because of its very low sulfur content. Otherwise, use of low-sulfur residual fuel oil is a reasonable option. For relatively minor increases in the cost of fuel, switching to 1.0%-S or 0.5%-S residual fuel oil provides significant reductions in fuel sulfur content with proportional reductions in SO_2 emissions.

When not firing on natural gas, Unit NT1 has burned 2.0%-sulfur residual fuel oil (actual average fuel sulfur content was 1.2% in 2002). It is estimated that switching to 1.0%-sulfur residual fuel oil would reduce SO2 emissions by about one-third, and switching to 0.5%-sulfur residual fuel oil would cut SO2 emissions by about two-thirds. At the 2002 production level of 700 million kilowatt-hours, estimated annual costs (long-term average, 2008\$), would be about \$3.3 or \$6.6 million (equivalent to \$0.0047 or \$0.0094 per kWh), respectively. The cost per kilowatt-hour would vary more or less in proportion to the fuel price differential and would not change significantly with increases or decreases in production level.

Fuel switching could be accomplished without capital outlay and would have predictable costs tied directly to fuel consumption and fuel price differentials. A major consideration is fuel availability. In recent years, there have been sudden and dramatic swings in the price of natural gas relative to fuel oil as supply/demand has shifted. The future price and availability of natural gas are difficult to discern. While regional and national supplies of 1.0%-sulfur residual fuel oil appear to be adequate to meet current demand, the present and future availability of 0.5%-sulfur residual fuel oil, in particular, is uncertain and speculative.

After consideration of projected costs, ease of implementation, and fuel availability, it is determined that using 1.0%-sulfur (low-sulfur) residual fuel oil is currently the Best Available Retrofit Technology for PSNH Newington Station Unit NT1 when natural gas is not available at reasonable cost. The use of 0.5%-sulfur (ultra-low-sulfur) residual fuel oil remains a future possibility that should be re-evaluated within the next few years. A further reduction in the sulfur content of fuel oil burned at this facility would be consistent with MANE-VU's plan to reduce sulfur levels to 0.25-0.5% for all fuel oils throughout the region by 2018.

NPS: NHDES concluded that a FGD system is too expensive. We agree with the NHDES approach that use of lower-sulfur fuels is BART for this EGU. And, we commend NHDES for its proposal to reduce the sulfur limit on the #6 residual oil to 1%. Although NHDES also concludes that the cost of switching to 0.5% sulfur fuel oil is also reasonable (@ \$1,900/ton—the same as the cost to go to 1.0% sulfur oil—it has deferred proposing that this additional reduction be required at this time. NHDES suggests that "future availability of 0.5%-sulfur residual fuel oil, in particular, is uncertain and speculative" and that its use "should be re-evaluated within the next few years." To support this contention, NHDES should present information from fuel oil suppliers concerning the uncertain availability of 0.5% sulfur oil. Furthermore, NHDES should explain how and when it would re-evaluate that issue and implement a requirement for 0.5% sulfur oil if it found it to be sufficiently available.

We believe that, if 0.5% sulfur fuel oil is found by NHDES to be reasonably available in the future, a determination that BART is 0.5% sulfur would be consistent with, and enhance the goals of the Northeast states as discussed in the document: "Low Sulfur Heating Oil in the Northeast States: An Overview of Benefits, Costs and Implementation Issues" provided by NHDES as attachment AA. For example, the Executive Summary of that document states:

> The analysis summarized in this White Paper supports the Northeast states' conclusion that significant reductions in SO_2, NO_X, and PM emissions can be achieved by mandating lower sulfur heating oil. Importantly, these reductions can be achieved with an expected cost savings to the consumer. Adding the public health and environmental benefits associated with lower sulfur fuel increases the favorable cost-benefit ratio of a regional 500 pm sulfur heating fuel program.

BART Analysis for NO_x

STEP 1 – Identify all available retrofit emissions control techniques

NHDES: NO_X control technology options available and potentially applicable to Unit NT1 are combustion controls, selective non-catalytic reduction, and selective catalytic reduction.

NPS: NHDES identified a reasonable suite of options.

STEP 2 – Eliminate technically infeasible options

NPS: No NO_X control options were eliminated on this basis.

STEP 3 – Evaluate control effectiveness of remaining control options

NHDES: NO_X emission reductions of about 75 to 90 percent have been obtained with selective catalytic reduction (SCR) on coal-fired boilers in the U.S.

NPS: NHDES should explain why the SCR cannot achieve better than the estimated 85 percent control.

STEP 4 – Impact analysis

NHDES: The estimated costs of NO_X emission controls for SNCR and SCR at Newington Station Unit NT1 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 EGU the size of Unit NT1. For SNCR, the total annual cost is estimated to be about $730,000, or $1,030/ton of NO_X removed. For an SCR system, the total annual cost is estimated to be $1,410,000 or $1,180/ton. Because Unit NT-1 is primarily a peak-load generator, these estimates are based on a 20-percent capacity factor.[3]

[3] 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 400-MW unit with 20% capacity factor and 701million kWh

NPS: When we applied different assumptions for SCR (e.g., 90% NO_x control, 20-year life, 7% interest) we arrived at a slightly higher ($1,278) cost/ton. Furthermore, Newington's capacity utilization and emissions have dropped so much in recent years that it is doubtful that any major capital expenditures would be justified as long as that low utilization continues. For example, in 2007, CAM data show that heat input had declined to 4.3 trillion Btu, and that NO_X emissions were 415 tons.

STEP 5 – Determine visibility impacts
(same as above for SO_2)

Determination of BART for NO_x
NHDES: For the reasons below, the existing controls, which include Low- NO_X burners, overfire air, and water injection, are determined to be BART for Newington Station Unit NT1:

- Many of the NO_X reduction benefits acquired through the implementation of low excess air are already being achieved at Unit NT1 through the use of Low-NOX burners and overfire air.
- The additional reductions in NO_X emissions that would result from adding SCR or SNCR would come at a cost of about $0.7 to $1.3 million annually, with incremental NO_X reductions in the 300 to 700 ton/year range. This cost range does not include costs related to redesign of the site layout to accommodate existing spatial constraints. Also, this estimate is based on 2002 emission levels, when the plant's capacity factor was around 20 percent. With the capacity factor having fallen to less than 10 percent over the period 2006-2008, it is difficult today to justify additional technology retrofits to reduce NO_X emissions at this facility.
- For SNCR, the total annual cost is estimated to be about $730,000, or $1,030/ton of NO_X removed. For an SCR system, the total annual cost is estimated to be $1,410,000 or $1,180/ton. SCR and SNCR are not cost-effective as Best Available Retrofit Technology for this facility and will not be considered further.
- Another consideration with SCR or SNCR is flue gas and fugitive ammonia emissions. Based on past operation of Unit NT1 and on typical ammonia "slip" rates, it is estimated that fugitive ammonia emissions with either technology would be in the vicinity of 32 tons annually. Ammonia is a regulated toxic air toxic pollutant in New Hampshire and is also a significant contributor to visibility impairment.

NPS: We agree that the reduced capacity utilization makes it difficult today to justify additional technology retrofits[4] to reduce NO_X emissions at this facility. NHDES should propose federally-enforceable BART limit(s) that reflect its BART determination.

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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 704 tons of NO_X removed for SNCR and an estimated 1,196 tons of NO_X removed for SCR.

[4] NHDES has approved SCR (and the associated issues with ammonia) at Merrimack and must explain how it arrived at its estimate for ammonia slip and why ammonia is more of a problem at Newington. If NHDES believes that ammonia slip will impair visibility, it must show why that outweighs the benefits of reducing NO_x.

BART Analysis for PM

STEP 1 – Identify all available retrofit emissions control techniques
NHDES: The only PM control technologies available and potentially applicable to Unit NT1 are electrostatic precipitators, fabric filters, mechanical collectors, and particle scrubbers.

NPS: NHDES should have considered simple, inexpensive upgrades for the ESPs to achieve greater control.

STEP 2 – Eliminate technically infeasible options
NPS: No PM control options were eliminated on this basis.

STEP 3 – Evaluate control effectiveness of remaining control options
NHDES: Existing electrostatic precipitators (ESPs) are typically 40 to 60 percent efficient. New or rebuilt ESPs can achieve collection efficiencies of more than 99 percent. Collection efficiencies of baghouses may exceed 99 percent.

NPS: NHDES assumed 42% for the existing ESP at Newington. Because this is far short of the capabilities of a rebuilt ESP, NHDES should have evaluated that option.

STEP 4 – Impact analysis
NHDES: The costs for ESPs and fabric filters are of similar magnitude, with total annual costs ranging from about $3.2 million to $10.4 million, or $14,000 to $63,000 per ton of PM removed. Because Unit NT1 already has an ESP installed and operating, the tabulated costs are useful for comparative purposes only.

NPS: NHDES should have evaluated upgrading the ESP.

Determination of BART for PM
NHDES: PSNH currently operates an electrostatic precipitator on Unit NT1. ESPs perform with removal efficiency rates similar to those of fabric filters but operate at about half the cost for plants of this size. Because of the estimated cost differential and the fact that an ESP is already installed and operating, the existing ESP is determined to satisfy BART requirements for PM removal at PSNH Newington Station Unit NT1.

NPS: However, NHDES has assumed that the existing ESP is only 42% efficient—which is not "similar' to a fabric filter. NHDES should propose a limit that reflects the 99% control it assumed in its analyses for a new ESP or fabric filter. Although the existing ESPs may well represent BART, NHDES should evaluate possible upgrades, or, at least, establish a federally-enforceable permit limit that reflects the actual capabilities of the unit.